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No. 05-848

Supreme Court, U.S.
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In The
Supreme Court of the United States

ENVIRONMENTAL DEFENSE, *et al.*,

Petitioners,

v.

DUKE ENERGY CORPORATION, *et al.*,

Respondents.

On Writ Of Certiorari To The United States Court Of Appeals For The Fourth Circuit

JOINT APPENDIX
VOLUME II, Pages 266 to 509

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EXHIBIT 76

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[Addresses Omitted In Printing]

June 5, 1989

Ms. Polly Gault
Chief of Staff to the Secretary
United States Department of Energy
1000 Independence Avenue, S.W.
Room 7A257
Washington, D.C. 20585

Dear Polly:

I appreciated the opportunity to meet with you and discuss the so-called *WEPCo* case and its progeny. Enclosed is a briefing paper which explains the problem and outlines how EPA could easily solve it administratively. As discussed in the enclosure, the consequences of these decisions are far reaching. Among other things,

1. *WEPCo* will wholly undermine any "acid rain" legislation designed to allow reductions in the most cost-effective way;

2. *WEPCo* is presently causing utilities to defer needed major maintenance, repair and replacement projects required for maintaining a reliable electric supply;

3. Utilities and others that want to reduce emissions by converting to natural gas are barred from doing so without a PSD new

source permit unless they were capable of burning gas in 1975; and

4. If the *WEPCo* rationale is not qualified, utilities face substantial risks in undertaking a "clean coal" demonstration project.

As I mentioned at our meeting, we have asked Administrator Reilly to reconsider the *WEPCo* interpretations. We know that the EPA staff will oppose our request. This steadfast refusal to back down is best illustrated by a May 5 letter to Detroit Edison where Acting Assistant Administrator Don Clay stated:

> In your March 13 letter, you provided data that illustrated large decreases in the source's "potential to emit" sulfur dioxide, particulate matter . . . and NOx as a result of the conversion. [Nevertheless,] [o]ur review of the available information suggests that Region V's conclusion that the source appears to be subject to PSD review . . . is correct.

We hope the Department and others in the Administration will urge Administrator Reilly to overrule his staff on this important issue. I am sending Linda Stuntz, under separate cover, more detailed information on the WEPCo case, including an *amici* brief supporting Wisconsin Electric in the Seventh circuit litigation. That brief, joined in by the aluminum, steel, utility, petroleum, and coal industries, underscores the broad and adverse impact *WEPCo* will have on energy policy and on our economy.

If I can provide any additional information, please let me know. We would appreciate the opportunity to meet with you and others in the Department within the next

few weeks to discuss analyses we are preparing on the impact of *WEPCo* on the utility industry.

Sincerely yours,

/s/ Henry
Henry V. Nickel

Enclosure

cc: Linda Stuntz, Esquire (w/enclosure)
Mr. Walker Nolan (w/enclosure)
Ms. Lynn LeMaster (w/enclosure)

June 5, 1989

THE WEPCO, DETROIT EDISON, AND OHIO EDISON DECISIONS

In October 1988, Administrator Thomas affirmed a determination of then Acting Assistant Administrator Don Clay finding that new source performance standards (NSPS) (i.e., SO2 scrubbers) and prevention of significant deterioration (PSD) new source permitting requirements would apply if a maintenance, repair, and replacement project (called a "life extension" project) planned at a five unit coal-fired electric generating plant owned by Wisconsin Electric Power Company (WEPCo) went forward. WEPCo was seeking to replace equipment that posed safety concerns at four of the units and required shutdown of one of those units. In addition, replacement of defective equipment was required at two units to allow those units to operate again at design capacity. The remainder of the repairs and replacements in the project were needed to improve efficiency and reliability without having any impact on emission rates.

On February 15, 1989, Acting Assistant Administrator Clay resolved additional issues posed by WEPCo. Among other things, he determined that WEPCo could not avoid NSPS by switching to as lower sulfur coal, but rather would need to install scrubbers or similar controls. He also found that PSD review would be required even though the units were not increasing their emission rate.

In the *Detroit Edison* case, EPA Region V determined that a project to allow natural gas-firing at an oil-fired plant could not be undertaken without a PSD permit. In a May 5 letter, Don Clay observed that the project would substantially reduce emissions, but he nevertheless tentatively concluded that Region V's PSD determination appears to be "correct.

In the *Ohio Edison* case, EPA determined that removing a clean coal technology demonstration project after the demonstration concluded would trigger PSD and NSPS requirements. Although EPA Acting Assistant Administrator Clay promised "no action" in terms of EPA civil enforcement, "clean coal" participants would still potentially face criminal penalties for "knowing" violations of the Clean Air Act and would be subject to citizen suits under the Act. In other words, EPA has made clear that removing a clean coal demonstration project is unlawful (in EPA's view) and has informed those undertaking these demonstration projects that, at most, EPA will not initiate a civil action. Citizens and a local U.S. Attorney can do what they want.

The Utility Air Regulatory Group[1] has requested that Administrator Reilly reconsider these decisions. Detroit Edison is separately seeking review of the Region V decision concerning its natural gas project.

EPA's New Interpretation of the NSPS and PSD Requirements

New Source Performance Standards (NSPS) require new sources to meet a 70-90% scrubbing requirement and other stringent emission limitations. The Prevention of Significant Deterioration (PSD) permit program imposes numerous monitoring and modeling requirements on new sources, as well as technology-based emission limits that are potentially more stringent than NSPS. Existing sources are subject to NSPS and PSD if they are "modified," that is, if they undergo physical or operational changes that increase emissions.

The *WEPCo, Detroit Edison,* and *Ohio Edison* decisions substantially expand the previous understanding of what is a "modified" source for NSPS purposes. Under these decisions, if emissions immediately before a "non-routine" (as determined by EPA staff) change are greater than emissions after the change, NSPS is triggered. This is the case notwithstanding the fact that the emissions

[1] The Utility Air Regulatory Group (UARG) is a voluntary, nonprofit, unincorporated, ad hoc group of 65 electric utilities, the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. UARG's purpose is to participate on behalf of its members collectively in federal air pollution control regulatory activities and in related litigation. Since 1977, UARG has been involved in all major Environmental Protection Agency Clean Air Act rulemaking and in numerous judicial proceedings related to these rulemakings.

immediately before the change are not representative of normal source operations.

EPA similarly expanded the "modification" requirements that apply to the PSD program. Under these decisions, if EPA finds a change to be "non-routine," EPA will always conclude that the change causes an emissions increase since EPA compares actual annual emissions before the change with the emissions projected from operating 100 percent of the time, at 100 percent capacity, for 365 days. This approach, which allows projects an emission increase, conflicts with the plain language of EPA's rules.

EPA's decisions acknowledge that "routine" repairs and replacements are not subject to the NSPS and PSD modification rules. However, the Agency has arbitrarily redefined what repair and replacement activities are "routine," such that "routine" activities include only those that (1) are frequently done at that plant, (2) involve no major equipment, (3) are inexpensive, and (4) do not extend the life of a plant. This new interpretation is vastly different from past implementation of the "routine" rule, which included any repair and replacement activity that is normal business practice. It gives EPA staff virtually unlimited discretion to find that any major repair or replacement project is "non-routine."

Direct Impacts of the WEPCo,
Detroit Edison, and Ohio Edison Decisions

Under these decisions:

1. A unit that discovers safety problems due to an unanticipated defect in equipment and shuts down pending repairs cannot resume operations without

meeting stringent new source standards and receiving a new source prevention of significant deterioration ("PSD") permit. This occurs whenever EPA determines the repair or replacement is not "routine." *WEPCo,* Port Washington Unit 5, October 14 letter.

2. A unit, under the *WEPCo* decision, cannot repair or replace deteriorated or defective equipment needed to return to past maximum operating levels, unless the repairs or replacements are "routine." *WEPCo.*

3. A unit cannot avoid an emissions increase that would trigger new source standards by switching to a lower sulfur coal oil, or to natural gas. It must install control technology (e.g., scrubbers). *WEPCo,* February 15 letter.

4. A utility experiencing increased forced outages at its units due to equipment problems cannot undertake repairs needed to avoid serious electric reliability problems without applying for and receiving a PSD permit, even though these repairs will only improve reliability and efficiency and will not increase the emission rate of the units. This occurs whenever EPA determines these "emissions neutral" or even "emissions beneficial" repairs or replacements are not "routine." *WEPCo, Detroit Edison.*

5. A unit that was not able to burn a lower polluting fuel (e.g., natural gas) in the past cannot be converted to burn that fuel without first applying for and receiving a PSD permit. *Detroit Edison.*

6. A unit that has undertaken a "clean coal" demonstration project must meet new source standards and obtain a PSD permit if it wishes to remove the experimental technology at the end of the demonstration period. EPA may issue a "no action" assurance to such a project. *Ohio Edison.* A "no action" assurance is a promise by the EPA signatory – (in the case of *Ohio*

Edison, an Acting Assistant Administrator) that EPA will not bring a civil enforcement action. This does not insulate the company from a "citizen suit" under the Clean Air Act. Also, as the attachment to the EPA *Ohio Edison* letter makes clear, a U.S. Attorney can still bring-a criminal prosecution.

Broader Consequences of the WEPCo, Detroit Edison, and Ohio Edison Decisions

1. *WEPCo* will wholly undermine any "acid rain" legislation designed to allow reductions in the most cost-effective way. For example, it subjects many older, smaller units to scrubbers when these units are the logical candidates for fuel switching.

2. *WEPCo* is presently causing utilities to defer needed major maintenance, repair and replacement projects required for electric system reliability. The consequence of such deferrals is that utilities must risk interruption of service in the very near future or costly expenditures on short-term solutions (e.g., unplanned installation of combustion turbines). Given the time required to obtain a PSD permit to undertake a repair program at an existing unit or to install a new combustion turbine, a substantial deterioration in electric reliability in the near future – with serious health and environmental consquences – is likely unless *WEPCo* is revisited.

3. For other industries, *WEPCo* says: you may not undertake major repairs or replacements that restore a plant to its past levels of production unless someone in an EPA region or EPA headquarters finds that the project is "routine." Given EPA's restrictive interpretation of "routine," the *WEPCo* decision means that such projects cannot be undertaken without assuming

substantial risks or seeking a determination from EPA that could take 6 to 12 months.

4. Even more troublesome is the WEPCo determination that major repairs and replacements that improve "reliability" and "efficiency" but do not increase (and may even *reduce*) emission rates can require a PSD permit unless EPA determines that the project is "routine. This aspect of the WEPCo decision is hostile to improving the productivity of our basic industries.

5 Utilities and others that want to reduce emissions by converting to natural gas are barred from doing so without a PSD permit unless they were capable of burning gas in 1975. This will cause companies to abandon such conversions in many cases and delay them (due to PSU permitting requirements) whenever a company decides to proceed.

6. If the WEPCo rationale is not qualified, utilities face substantial risks undertaking a "clean coal" demonstration project. If new source requirements apply upon removal of the experimental controls, a unit will have to be shut down or, face very costly retrofit controls. The price may be too great for many companies, thereby discouraging participation in the program.

Adminsitrative Solution to the WEPCo, Detroit Edison, and Ohio Edison Cases

In the *WEPCo, Detroit Edison,* and *Ohio Edison* decisions, EPA interpreted its new source performance standards (NSPS) and prevention of significant deterioration (PSD) requirements in an unprecedented manner. While the rules governing these EPA programs are complex, the EPA determinations in these cases could be easily overcome with the following interpretations:

1. For NSPS purposes; EPA can, and should, recognize that, in determining an emissions increase, representative operations of the unit should be used in comparing past emissions to future emissions after a change. Nothing on the face of EPA's regulations or their regulatory history precludes such a declaration by the new EPA Administrator. Such a "clarification" would mean that "clean coal" technologies could be removed at the end of the demonstration period, without triggering NSPS. It would also allow utilities and other industries to make necessary repairs to return plants to past maximum production levels.

2. For PSD purposes, EPA can, and should, recognize that any emission increase predicted to occur as a result of an increase in hours of operation or production rate up to original design capacity (unless limited by a federally enforceable restriction on production or hours) is an exempt emission increase, as § 52.21(b)(2)(iii)(f) of EPA's rules explicitly and unambigiously provides. This reconsideration of the *WEPCo, Detroit Edison,* and *Ohio Edison* decisions would allow "clean coal" projects to proceed without having to receive a PSD permit. It would also allow industry to convert to lower-emitting natural gas without a PSD permit.

EXHIBIT 82

February 9, 1989

W. O. Parker, Jr.

Subject: EEI Prime Movers – WEPCO

The following is a summation of the discussion with WEPCO and other utilities about the WEPCO case.

I have shared this information with the review committee and FPD GO managers. We may want to add this to the managers' meeting agenda as a 30 minute update item.

Feel free to use this report as you see fit in updating others in management about what we learned.

Major points from the *WEPCO* discussion:

- WEPCO must send a letter notifying thier commission of plans to do work costing more than $1,000,000.
- WEPCO must get a certificate from the commission for any work over $2,000,000.
- WEPCO filed for certificate with the Commission to do $71,000,000 of repair and upgrade work.
- Commission ask State environmental group to review work in relationship to PSD and NSPS standards.
- Wisconsin like NC has a state operated program approved by EPA.
- W.E.C. requested EPA Region 5 to review.
- Region 5 responded that PSD was triggered and NSPS applied because modification work:
    - Increased efficiency (rebuilt preheater).
    - Increased capacity (corrected drum).

- Increased emission above the level emitted for the prior two years.
- Resulted in significant spending, $71 M or 20% of replacement generation cost.

- *WEPCO* requested review by Washington.
- Washington supported Region 5 decision.
- *WEPCO* has filed suit against EPA.
- Lawyers estimate 11 to 23 months.
- Florida Power Corporation – Port Everglades plant is under going similiar work.
- AEP – Has taken no units out but is doing the same type of work that we are doing.
- Court case should clear interpretation of cost (50% vs. less) and increased emissions time frame (prior 2 years) standard.
- NC Environmental Air is acting like they are not aware of WEPCO.

WEPCO Recommended that others SHOULD NOT:

- ★ Derateunits.
- ★ Remove from servicefor extended periods.
- ★ Do large major repairs as one project (WEPCO less the $1 M increments)
- ★ Project retirement datesfor units as this establishes the useful end point or life of a particular unit.

J. O. Fayssoux
Fossil Production Department

JOF:mmp

EXHIBIT 93A

NSPS/PSD Implications of Plant Modifications

New Source Performance Standards: [For Boiler Only]

Apply to new facilities or modifications to existing facilities.

For NSPS, modification is defined as:

- **any physical or operational change which:**
- **results in an increase in maximum hourly emissions.**

Maximum hourly emissions are determined by the maximum which can be demonstrated over the past five years. This should be compared to what the maiximum emissions will be after the change.

NSPS does not apply to any action which can be classified as routine maintenance, repair, or replacement, or to work which can be accomplished without a capital investment. The federal court ruled in WEPCO that EPA was correct in saying that WEPCO's decision to forego repairs and allow the unit to deteriorate over a long period of time was evidence that the planned work was not routine. Based on that ruling, the five year test was put into the regulation.

Prevention of Significant Deterioration: [Total emissions over a year]

Similar criteria to NSPS, but considers emissions over an annual period and applies whether or not the project is a capital expense. Increased production which could not otherwise be achieved without the modification will trigger PSD requirements.

[Last (five) 5 years maximum hourly emission routine maint. (capacity) replacement

Gross MW

1. .5%

AP42 calculated emissions based on fuel input allow 3 ID. Fan – max capacity test]

EXHIBIT 98

[SEAL]

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON D C 20460

Mr. John W. Boston
Vice President
Wisconsin Electric Power Company
Post Office Box 2046
Milwaukee, Wisconsin 52301

Dear Mr. Boston:

This is a revised final determination, on reconsideration, regarding the applicability of the Clean Air Act's New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) provisions to the proposed life extension project at the Port Washington steam electric generating station, which is owned and operated by Wisconsin Electric Power Company (WEPCO). This determination supplements the determination set forth in an October 14, 1988 letter to you from Lee M. Thomas, which in turn incorporated my September 9, 1988 memorandum. I find it necessary to reconsider EPA's original determination and issue this revised determination in part to address matters raised by, and new information submitted by, WEPCO representatives since, the October 14 letter. WEPCO believes that these new aspects call into question the accuracy of EPA's prior determination.

For the following reasons, EPA today reaffirms, with limited exceptions detailed below, its earlier findings regarding the Port Washington life extension project. I hereby incorporate by reference the October 14 letter and

the September 9 memorandum. and reaffirm the findings and conclusions in those two documents except where they are specifically superseded below.

This action constitutes final agency action for purposes of judicial review under section 307(b) of the Clean Air Act, 42 U.S.C. § 7607(b).

I. CAPITAL EXPENDITURE

EPA explained in its earlier determination that under the General Provisions of the NSPS regulations, a physical or operational change which increases emissions at an affected facility is a modification subject to NSPS. See 40 CFR 60.14(a). However, 40 CFR 60.14(e) provides certain exceptions to that general rule. In particular, section 60.14(e)(2) provides that an increase in production rate, at an affected facility would not, by itself, be considered a modification if that increase is accomplished without a capital expenditure.

As has been discussed in recent meetings between WEPCO and EPA, the October 14, 1988 letter from Lee M. Thomas was based in part on information supplied by WEPCO in a letter dated October 11, 1988 which indicated that the increase in production rate at each of the five units would be accomplished with a capital expenditure. On October 13, 1988, and November 22, 1988 WEPCO submitted revised capital expenditure calculations. EPA has carefully reconsidered its earlier determination based on those two additional submissions.[1] However, as explained

[1] The October 13, 1988 submission was not received in time to be considered in issuing EPA's letter of October 14, 1988.

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below, they provide no grounds on which to alter EPA's earlier finding on capital expenditure.

The modification provisions are designed in part to subject to NSPS these emissions increases caused by an increase in production rate that is in turn attributable to a significant investment in improvements to the capital stock. Consistent with this intent capital expenditure calculations employ the total, as opposed to annual, cost of a given project at each affected facility.

Thus, the December 16, 1975 preamble to the promulgated definition of capital expenditure states that " . . . the *total* cost of increasing the production or operating rate must be determined. *All* expenditures necessary to increasing the facility's operating rate must be included in this total" (40 FR 58416) (emphasis added). The total cost of the planned work at each facility is then compared to the product of the existing facility's basis and the annual asset guideline repair allowance percentage used by the Internal Revenue Service for taxation purposes. If the total project cost for each facility exceeds the product of the basis and repair percentage for each facility, there is a capital expenditure at that facility. See 40 CFR 60.2.

It is appropriate to accumulate, for capital expenditure purposes, the cost of the renovations necessary to increase the facility's production rate, because the overall work necessary to increase a facility's production rate pursuant to a particular renovation project is the same whether the work is performed in one calendar year or during two (or more) years. The use of annual costs could encourage sources to distort normal business planning by artificially stretching out costs over time as a means of

evading a finding of capital expenditure and consequent NSPS coverage.[2]

Rather, the purpose of the exemption in 40 CFR 60.14(e)(2) is to exclude from NSPS coverage increases in production rate that are accomplished without "an expenditure for long-term additions or improvement." See 39 FR 36948 (preamble to proposed NSPS regulations). Where the economic realities of the case are that increased production and, hence, emissions, are due to normal fluctuations in the business cycle rather than a considered decision to invest in substantial capital improvements, the NSPS do not apply.

The letter submitted on October 13 from Neil Childress of your staff to Gary McCutchen of EPA presented *updated* basis figures (determined by multiplying the original capital investment in the facility by a coefficient representing the inflation in construction costs between the year of the investment and the year in which the capital expenditure calculation is made) for each of the emissions units at Port Washington. These figures included costs of repair or replacement of equipment, such as steam turbines, that is not part of the existing affected

[2] Indeed, it appears that WEPCO may have extended the planned length of the Port Washington life extension project for precisely this purpose after being informed by EPA in the October 14, 1988 letter that there would be a capital expenditure using the original schedule. The unit 1 renovations have been extended from four years to five; unit 2 has been extended from four years to six; unit 3 has been extended from three years to six; unit 4 has been extended from two years to four. (Compare Telecopier Transmission, Neil Childress, WEPCO, to Gary McCutchen, EPA, October 11, 1988 (table attached to Response to Question No. 4) with Letter, Neil Childress, WEPCO, to Walt Stevenson, EPA, November 22, 1988, at page 2.)

facility for NSPS purposes. Since applicability determinations under the NSPS modification provisions are based on the existing affecting facility, capital expenditure determinations likewise are limited to costs associated with the affected facility. For NSPS Subpart Da, the affected facility is the steam generating unit as defined at 40 CFR 60.40a. Therefore, EPA staff requested WEPCO to limit the basis figures to the steam generating unit.

The November 22, 1988 letter from Neil Childress to Walt Stevenson of EPA presented revised cost figures on the renovation work on steam generating units 1 – 4 related to the capital expenditure calculations. These November 22 basis figures are understood to be limited to costs associated with the affected facility. The November 22 letter also presented a revised and extended schedule for the renovation work, under which the costs of repairs in any one year would not exceed the product of the annual asset guideline repair allowance percentage, which is 5% for electric utility steam generating units, and the basis of each unit. Mr. Childress' letter concluded that since 5% of each unit's updated basis is not exceeded by the cost of renovation work in any one year, there would not be a capital expenditure at any of the units. The revised figures also show that the total costs for each unit over the entire renovation period would exceed the 5% basis figure by 50% to 325%.

As explained above, it is the total cost, not the annual cost of a renovation project that determines whether a capital expenditure has occurred. Accordingly, based on the calculations and total project costs in WEPCO's November 22, 1988 letter, the proposed project would result in a capital expenditure at each of the five Port Washington units, and those units would not qualify for the exemption in

the NSPS modification provisions at 40 CFR 60.14(e)(2).[3] As to unit 5, WEPCO did not submit cost data limited to the affected facility. Thus, I have no reason to alter EPA's original determination that WEPCO has not demonstrated that the increase in production rate at unit 5 can be accomplished without a capital expenditure.

In addition, I have determined that it is more appropriate to utilize the *original* basis of each affected facility (as adjusted to reflect past capital improvements), expressed in nominal dollars, rather that the *updated* basis, expressed in current dollars, in determining NSPS applicability. Thus, even if WEPCO were correct that annual renovation costs, rather than total costs, should be used in capital expenditure calculations, in this case a comparison of annual renovation costs and the (adjusted) original basis of each affected facility shows that a capital expenditure would still occur.[4]

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[3] WEPCO has argued that since the definition of capital expenditure at 40 CFR 60.2 refers to the IRS "*annual* asset guideline repair allowance percentage" (emphasis added), EPA is bound by the literal language of its own regulations to use annual rather than total project costs in making capital expenditure calculations. However, the regulations do not dictate such a result. Instead, on their face they call for a comparison between *total* renovation costs and the annual asset guideline. Had EPA intended the result suggested by WEPCO, it would have explicitly called for comparison of annual costs of the change for projects exceeding one year with the annual asset guideline. This it did not do. In addition, as indicated above, the purpose of the capital expenditure provision would not be served by annualizing project costs for capital expenditure purposes.

[4] It is worth noting in this regard that if EPA were to adhere to a literal reading of IRS guidelines as urged by WEPCO, it would have no choice but to use *original* basis as well as annualized costs in making capital expenditure calculations for Port Washington. Using this

(Continued on following page)

In making a more detailed inquiry into the capital expenditure matter in response to WEPCO's request, I have found that neither the NSPS General Provisions nor the preamble thereto contain any discussion of the matter of original versus updated basis, and that EPA has rarely been called upon to address this issue. However, upon review of EPA's past practice in this area. I have found that in developing performance standards for particular industries, EPA has provided the regulated community a mechanism to calculate the original basis in making capital expenditure calculations. See, e.g., "Equipment Leaks of VOC in Petroleum Refining Industry – Background Information for Promulgated Standards," EPA-450/3-81-015b, December 7, 1983.[5] This suggests that EPA intended the original basis to be utilized to determine whether a capital expenditure is going to be made.

Moreover, I believe that the use of original basis is consistent with the overall purpose of the NSPS modification regulations in general, and the capital expenditure provisions in particular. The effect of using original basis is that the greater the age of an affected facility, the more likely it is that a given investment resulting in increased production will be deemed a capital expenditure and trigger NSPS. This is consistent with Congress' intent in adopting new source performance standards. Older facilities are most likely to use outdated equipment which does

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formula, WEPCO would exceed the repair allowance percentage at units 1 – 5 for most years, and NSPS would still apply.

[5] This Background Information Document provides an alternative to the method prescribed in the General Provision when it is difficult to determine original costs. The formula uses replacement costs and an inflation index to "approximate the original cost basis of the affected facility."

not reduce pollution to the extent more current technology does. Congress included modified sources within the new source performance standards of section 111 to ensure the use of new technology on such sources. *See* CAA §§ 111(a)(2), 111(a)(4).

II. AIR HEATER RENOVATIONS AT UNIT 1

In January 1989, WEPCO asked EPA to determine whether replacement of the heat transfer surface elements on the unit 1 air heater would trigger PSD or NSPS applicability. However, in a letter dated February 3, 1989, WEPCO withdrew this request, asserting that it could not receive approval in the time necessary, while reserving the right to renew it at a later time as to unit 1 or any other unit at Port Washington. Because this issue may arise again, and because I believe it bears upon the project as a whole, I find it appropriate to address the matter of air heater element replacement. Based on the information submitted regarding this new plan, as well as the earlier
ıation submitted regarding air heater replacement
I conclude that if WEPCO were to proceed under its
ł and now withdrawn plan, it would not alter EPA's
finding that PSD and NSPS would apply. In order
ain this finding, it is useful to first summarize the
ıt facts.

iginally, WEPCO advised EPA that it planned to
the air heaters at unit 1 – 4 in their entirety. As
) explained:

> Air heaters are subject to the erosive and
> rosive effects of the flue gas passing through
> :m and require regular maintenance of the
> ıt transfer surfaces.

> The plate-type air heaters on Units 1 – 4 do not lend themselves to replacement of the individual elements. Worn sections have been patched and blocked, where accessible, over the years. Now, however overall corrosion and perforation has passed beyond the practical point of repair, and replacement of the air heaters is the economical way to maintain the air preheater system.
>
> The air heaters on Port Washington Unit 5 and the other units on the Wisconsin Electric System [other than Port Washington units 1 – 4] are of the Ljungstrom basket design, which allows the heat transfer surfaces (baskets) to be replaced easily ***

See, e.g., List of Port Washington Projects, p. 6 (Attachment to April 22, 1988) Letter from John W. Boston, WEPCO, to Gary McCutchen , EPA.

On January 11, 1989, WEPCO informed the State of Wisconsin that it was considering replacing all the plate elements at unit 1. In a letter to the State of Wisconsin, WEPCO described this project as routine repair work, "necessary to halt the continuing decrease in the capability of Unit 1," and submitted a list of 40 generating units where significant portions of the air heater have been replaced. See Letter, with attachment, from Mark P. Steinberg, WEPCO, to Dale Ziege, Wisconsin Department of Natural Resources, January 11, 1989.

In a telephone conversation with EPA staff the next day, WEPCO indicated that it desired to perform the unit 1 plate replacement work during a current unit outage; that intended to replace only half, not all, of the elements, at a cost of approximately $500,000; that it intended to

later scrap this work and replace the entire air heater as described in the original scope of work at a cost of $2,600,000; and that it was considering performing the same work at unit 4 also. See Record of Telephone Conversation between David Schulz, EPA, and Mark Steinberg, Neil Childress, and Walter Woelfle, WEPCO, January 12, 1939.

In a meeting on January 17, 1989, WEPCO related that if it replaced half of the plate elements now, it probably would replace the remainder as part of the total renovation project at a later date and *not* replace the air heater in whole. WEPCO also related that complete replacement of the plate elements should increase unit 1's capability to the original design capacity. Finally, WEPCO stated in response to questions from EPA staff. that none of the air heaters or plate elements at units 1-4 had ever been replaced in the past. See Memorandum, Meeting with WEPCO regarding the Port Washington Generating Station, from David Schulz, EPA, to Files, January 27, 1989.

In addition to the above information, I note that WEPCO's list of 40 units at which air heater element replacements have occurred include no units containing plate elements such as those on units 1-4 at Port Washington. Instead, all of the examples submitted are of the Ljungstrom basket type or the tubular type. I conclude that those examples are too dissimilar to the plate-type elements in use at units 1-4 to support WEPCO's contention that the work in question is routine.[4]

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[4] Further, even the list of air heater replacement work submitted by WEPCO did not establish this as routine repair work. Those 40 units

(Continued on following page)

Based on all of the foregoing, I find no reason to depart from EPA's earlier conclusion that PSD and NSPS would apply to the air heater work on unit 1. It appears that despite WEPCO's recent recharacterization of this work as a separate project, it is properly viewed as an integral part of the overall Port Washington life extension project. WEPCO cannot evade PSD and NSPS applicability by carving out, and seeking separate treatment of significant portions of an otherwise integrated renovation Program. Such piecemeal actions, if allowed to go unchallenged, could readily eviscerate the clear intent of the Clean Air Act's new source provisions. Accordingly, if seen as part of WEPCO's previously proposed renovation project, the recent recharacterization of the unit 1 air heater work does nothing to alter the factors determinative of PSD and NSPS coverage.

III. CAPACTY TESTING FOR UNITS 1-4

A. Impact of Test Results on NSPS Applicability.

In Lee Thomas' October 14, 1988 letter, EPA stated that baseline emissions for NSPS purposes are determined by hourly maximum capacity just prior to the renovations. EPA relied on actual operating data to determine that current maximum capacity at units 1-4 has significantly deteriorated, such that the restoration of original design capacity through the lift extension project would result in corresponding emissions increases. As to unit 5, EPA stated that current capacity at unit 5 is zero because it is

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comprise only a small fraction of total operating utility units, and even at the 40 units, air heater repair or replacement appears to have been a one-time occurrence, not routine repair.

physically inoperable. EPA rejected WEPCO's unsupported assertions that all five units could be operated at high capacities, but held open the possibility of further discussions on that point. Subsequently, in November and December of 1988, following discussions with EPA, WEPCO conducted capacity tests to determine current actual capacity.

Based on its review and analysis of the test data, EPA finds that the tests adequately demonstrate that units 2 and 3 can be operated at their original design capacity on a sustained basis. Accordingly, I hereby supersede EPA's earlier determination and find that NSPS would not apply to units 2 and 3 by virtue of the proposed renovations so long as the capacity of these units after completion of the work is no higher than demonstrated in the recent tests (694,000 and 690,000 pounds of steam per hour, respectively). As discussed in more detail below, this revised NSPS determination does not affect our determination that the PSD provisions would be applicable to the proposed work on these two units.

During the tests on units 1 and 4, WEPCO was able to operate these units at 497,000 and 586,000 pounds of steam per hour, respectively, representing 72% and 89% of these units' respective original design capacities. These tests are adequate to confirm EPA's original determination that units 1 and 4 are not capable of operating at their original design capacities, and that restoration of the lost capacity through the life extension will trigger NSPS coverage. EPA today also determines that these tests are not adequate to show that current actual capacity for purposes of establishing the NSPS baseline is as high as the levels achieved during the recent tests. Rather, I reaffirm that baseline for those units is determined by the

lower capacities reflected in recent actual operating data as set forth in Lee Thomas' October 14 letter. EPA must reject the tests for purposes of establishing actual NSPS baselines because during the testing discussed above, there were significant measured exceedances of the applicable particulate mass emission limit and several measured exceedances of the applicable opacity limit contained in the Wisconsin State Implementation Plan. One of the purposes of these tests was to determine the maximum actual capacity of the Port Washington units that can be achieved in a lawful manner. As a consequence of the measured exceedances, WEPCO's tests cannot be relied on to demonstrate that the company could lawfully sustain the levels achieved during the testing.

Regarding unit 5, I find that by declining to conduct or schedule capacity tests, WEPCO has effectively conceded that unit 5 is at present inoperable. Therefore, I reaffirm that its baseline for NSPS purposes is zero.

B. Impact of Test Results on PSD Applicability.

In its February 3, 1989 letter, WEPCO asserted that EPA's October 14, 1988 determination assumed that the emission rate of each unit would increase following the renovations. Thus, WEPCO claims, EPA did not address the question whether units that are not increasing their emission rates following renovation can be deemed to trigger PSD. WEPCO is incorrect on both counts.

EPA's prior determination explained that under the PSD program, unlike NSPS, baseline emissions are determined by representative actual emissions prior to the physical or operational change. Accordingly, the results of testing conducted by WEPCO, intended to determine

current maximum hourly capacity, have no impact on the existence of a significant net emissions increase for PSD purposes. Hence, those test results provide no reason to alter EPA's prior determination regarding PSD applicability.

Actual emissions are the product of the emission rate (amount of pollution per unit of production or throughout, e.g., pounds of sulfur dioxide per ton of coal combusted), the production rate or capacity utilization (amount of production or throughout per hour, e.g., tons of coal combusted per hour), and the hours of operation (e.g., hours per year). In its prior determination, EPA explained that an increase in any one of these three factors, if attributable to a physical or operational change, can trigger an emissions increase for PSD purposes, and rejected WEPCO's contention that only increases in the emission rate were determinative. In so doing, EPA explicitly assumed that emissions increases at Port Washington would come not from an increase in emission rate, but rather from increases in production rate or hours of operation. See Memorandum from Don R. Clay, September 9, 1988 at 8.

WEPCO further implies in its February 3, 1989 letter that the demonstration that units 2 and 3 can operate now at maximum design capacity means that there will be no increase in production rate for PSD purposes following the renovations. This is not the case because PSD baseline emissions are determined by *representative actual* emission rate, production rate, and hours of operation prior to the physical change. Representative actual emissions are determined by examining "the actual emissions during a representative two year period, (See 40 CFR 52.21(b)(21)(ii)) which in this case the Administrator determined to be

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1983 and 1984 (See Lee Thomas' Oct. 14 letter, at 5). The hourly capacity demonstration for NSPS purposes is not relevant to the PSD analysis.

IV. NSPS OPERATIONAL LIMITATIONS

In my September 9, 1988 memorandum, I pointed out that an affected facility cannot avoid NSPS applicability by offsetting, through the use of fuel with a lower sulfur content, an increase in the emission rate that would otherwise occur due to a physical or operational change. As I explained at that time, 40 CFR 60.14(e) provides that use of an alternative fuel or raw material – such as higher-sulfur coal – which an existing facility was designed to accommodate before a physical or operational change does not constitute a modification for NSPS purposes. It follows that the facility cannot avoid NSPS by switching to lower-sulfur fuel to counteract a prospective increase in emission rate because, under the regulations, the facility would always have to option to switch back to a higher-sulfur fuel at a later date without triggering NSPS.

Subsequent to the issuance of EPA's October 14, 1988 letter, WEPCO inquired whether it might be able to utilize lower-sulfur coal to avoid NSPS at Port Washington, notwithstanding the regulatory provision explained above, by agreeing to federally enforceable permit conditions that would bar the company from switching back to higher sulfur coal in the future. Restrictions of this nature are acceptable for netting transactions under the Act's PSD provisions. However, the statute reflects a basic political decision that fossil fuel-fired sources not rely only on natural occurring less-polluting fuels to comply with the NSPS. Instead, Congress declared that compliance must

depend in part upon the application of flue gas treatment or other pollution control technologies. Thus, section 111(a)(1)(A)(ii) defines "standard of performance" for fossil fuel-fired sources as

> requiring the achievement of a percentage reduction in the emissions from such category of sources from the emissions which would have resulted from the use of fuels which are not subject to treatment prior to combustion. . . .

Congress further clarified this point in a later paragraph of section 111(a) by adding:

> For the purpose of subparagraph (1)(A)(ii), any cleaning of the fuel or reduction in the pollution characteristics of the fuel after extraction and prior to combustion may be credited . . . to a source which burns such fuel.

This core policy judgment is reflected as well in the legislative history of the 1977 Clean Air Act amendments. For example, the Conference Report states:

> The Senate concurs in the House provision with minor amendments. The agreement requires (1) that the standards of performance for fossil fuel-fired boilers be substantially upgraded to require the use of the best technological system of continuous emission reduction and to preclude use of untreated low sulfur coal alone as a means of compliance; . . . (3) that for fossil fuel-fired sources, the new source performance standards must be comprised of both a standard of performance for emissions and an enforceable requirement for a percentage reduction in pollution from untreated fuel.

H.R. Rep. No. 95-564, 95th Cong., 1st Sess. 130.

Because the will of Congress is so clear that lower-sulfur fuels alone will not suffice to *comply* with NSPS, it would be inconsistent with the legislative intent for EPA to allow sources to use lower-sulfur fuel to *avoid coverage* of NSPS in the first instance in the manner suggested by WEPCO. If EPA were to follow such a course, numerous modifications to existing facilities could escape coverage in a manner contrary to the statutory purpose.

V. THE TIMING OF THE LIFE EXTENSION PROJECT

In discussions with EPA, WEPCO has challenged, on grounds of timing, EPA's position on baseline emissions for NSPS purposes. In its prior determination, EPA explained that under the NSPS regulations, baseline emissions are determined by hourly maximum capacity just prior to the renovations. Thus, the baseline for unit 5 at Port Washington is zero because the unit has been shut down for several years due to safety concerns. In response, WEPCO has presented the hypothetical question whether EPA would still have found a zero baseline if unit 5 had been shut down on a Friday due to some unexpected or catastrophic failure of a major component previously in good working order, and WEPCO had sougt to replace that component on the following Monday. WEPCO asserts that in such circumstances, EPA should have established baseline emissions using the emissions rate just prior to the breakdown.

I. find it unnecessary to engage in speculation by addressing the hypothetical situation presented by WEPCO, because it is far removed from the true circumstances surrounding the proposed Port Washington life extension project. In fact, unit 5 has been shut down for

over four years, not a weekend, and that is the foundation of EPA's analysis and determination.

In conclusion, with limited exceptions, EPA today reaffirms the decisions reached in the October 14 determination. In addition, EPA has concluded that the work on each unit constitutes a capital expenditure and that the proposed air heater plate replacement work on unit 1. would trigger PSD and NSPS. As a result of the capacity test demonstration, however, I find that units 2 and 3 at Port Washington can be operated at their design capacity on a sustained basis. Therefore EPA's earlier determination with respect to NSPS applicability is superseded and NSPS would not apply to units 2 and 3 by virtue of the proposed renovations so long as the capacity of these units after the completion of this work is no higher than demonstrated in the recent tests. This determination does not affect PSD applicability for these two units. If you should have any questions about the foregoing, please feel free to contact me. Thank you for your cooperation in this matter.

Sincerely,

/s/ _____

Don R. Clay
Acting Assistant Administrator
for Air & Radiation

EXHIBIT 101

[LOGO] **UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

MAY 23 2000

REPLY TO THE ATTENTION OF
R-19J

Henry Nickel
Counsel for the Detroit Edison Company
Hunton & Williams
1900 K Street, N.W.
Washington D.C. 20006-1109

Dear Mr. Nickel:

I am responding to your request on behalf of the Detroit Edison Company for an applicability determination regarding the proposed replacement and reconfiguration of the high pressure section of two steam turbines at the company's Monroe Power Plant, referred to as the Dense Pack project. Specifically, you requested that the United States Environmental Protection Agency (EPA) determine whether the Dense Pack project at the Monroe Power Plant would be considered a major modification that would subject the project to pollution control requirements under the Prevention of Significant Deterioration (PSD) program.

We have reviewed your original request, dated June 8, 1999, and the supplemental information you submitted on December 10, 1999, and March 16, 2000. We provisionally conclude that the Dense Pack project would not be a major modification. Thus, Detroit Edison may proceed with the

project without first obtaining a PSD permit. Although the Dense Pack project would constitute a nonroutine physical change to the facility that might well result in a significant increase in air pollution, Detroit Edison asserts that emissions will not in fact increase due to the construction activity, and EPA has no information to dispute that assertion.

As you know, nonroutine changes of any type, purpose, or magnitude at an electric utility steam generating unit – ranging from projects to increase productions efficiency to even the complete replacement of entire major components – are excluded from PSD coverage as long as they do not significantly increase emissions from the source. Thus, Detroit Edison has been free to proceed at any time with the Dense Pack project without first obtaining a PSD permit as long as it adheres to its stated intention to not increase emissions as a result of the project. Indeed, EPA encourages the company to proceed with the project on this basis, since it appears to both reduce emissions per unit of output and not increase actual air pollution.

As you are also aware, under the applicable new source review regulations, in determining if a physical change will result in a significant emissions increase at an electric utility plant, companies may use an "actual" to "representative actual annual emissions" test for emissions from the electric utility steam generating unit, under which a calculation of baseline emissions and a projection of future emissions after the change is needed. Our determination of nonapplicability is provisional because Detroit Edison has not, to our knowledge, provided a calculation of baseline emissions or projected future emissions to the permitting agency, and this should be done prior to the start of construction. The basis for this determination is

summarized below and is set forth in full in the enclosed detailed analysis.

In determining whether an activity triggers PSD, the Clean Air Act and EPA's regulations specify a two-step test. The first step is to determine if such activity is a physical or operational change, and if it is, the second step is to determine whether emissions will increase because of the change. The statute admits of no exception from its sweeping scope, but EPA's regulations contain some narrow exceptions to the definition of physical or operational change. In particular, Detroit Edison claims that the Dense Pack project is eligible for the exclusion for routine maintenance, repair, and replacement. The determination of whether a proposed physical change is "routine" is a case-specific determination which takes into consideration the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors. After carefully reviewing all the information you submitted in light of the relevant factors, EPA has determined that the proposed project is not "routine."

The purpose of the Dense Pack project, to significantly enhance the present efficiency of the high pressure section of the steam turbine, signifies that the project is not routine. An upgrade of this nature is markedly different from the frequent, inexpensive, necessary, and incremental maintenance and replacement of deteriorated blades that is commonly practiced in the utility industry. For instance, past blade maintenance and replacement of only the deteriorated blades at Detroit Edison has never increased efficiency over the original design. Accordingly, because increasing turbine efficiency by a total redesign of a major component is a defining feature of the proposed Dense Pack project, it clearly goes significantly beyond

both historic turbine work at Detroit Edison, and what would otherwise be considered a regular, customary, or standard undertaking for the purpose of maintaining the existing steam turbine units. The project also goes well beyond routine turbine maintenance, repair, and replacement activities for the utility industry in general.

The nature and extent of the work in question – replacement of the entire high pressure sections of the steam turbines for Units 1 and 4 at Monroe – suggests that the Dense Pack project is not routine. It would result in greater efficiency above the level that can be reached by simply replacing deteriorated blades with ones of the same design and, in addition, will substantially increase efficiency over the original design. Specifically, the Dense Pack upgrade would not only restore the 7 percent of the efficiency rating lost over the years at each unit but would improve the unit's efficiency by an additional 5 percent over its original design capacity. Accordingly, the proposed project represents a significant and major redesign and replacement of the entire high pressure sections of the steam turbines at Units 1 and 4 at the Monroe facility.

The frequency with which utilities have undertaken turbine upgrades like the Dense Pack project also indicates the nonroutine nature of the changes. The information provided by Detroit Edison, regarding past history at the Monroe facility, describes what is characterized as necessary maintenance, repair, and replacement of deteriorated turbine blades approximately every 4 years. During these overhaul periods, it is not uncommon for the company to replace up to several turbine blades at one time. It is common among other utilities to also perform similar turbine maintenance. However, Detroit Edison has not provided any information to suggest that a complete

replacement and redesign of the high pressure section of a steam turbine is conducted frequently at Monroe or at any other individual utility. Instead, Detroit Edison relies on its claim that projects "similar" to the Dense Pack project have been performed at a number of utilities. This information does not indicate that the replacement of the high pressure section of the steam turbine is frequent at the typical utility source; to the contrary, the only available information reflects that projects like the Dense Pack project have been performed only one time, if ever, at individual sources.

The cost of the Dense Pack project is significant and tends to indicate that this project is nonroutine. Detroit Edison expects the Dense Pack replacement to cost approximately $6 million for each turbine unit, for a total of $12 million. The EPA has rejected claims of routineness in past cases where the cost was substantially less than this figure. Moreover, Detroit Edison intends to capitalize the entire cost of this project, and EPA believes that a $12 million project that is 100 percent capital improvement indicates that it is a major undertaking.

Beyond the clearly significant absolute cost of this project, available information suggests that this expenditure far exceeds the cost typically associated with turbine blade maintenance activity. Detroit Edison provided only a summary of the total project costs for past maintenance and inspections at the facility, the total costs of which ranged from less than $1 million to a little more than $6 million. Although Detroit Edison did not provide any detail regarding what specific activities comprise these aggregated amounts, it acknowledges that it spent only $18,700, $33,100, and $7,900 to replace high-pressure rotors in three turbine projects in 1981 and 1982. Further, the

project is significantly more costly than simply replacing deteriorated blades today; Detroit Edison acknowledges that the Dense Pack upgrade would cost three times more than its alternative blade repair and replacement project. Accordingly, it appears that the costs associated with the Dense Pack project greatly exceed the amounts spent previously by Detroit Edison or that it would spend presently for the replacement of deteriorated turbine blades or rotors.

For the reasons delineated above, we conclude that the changes proposed by Detroit Edison are not routine. Detroit Edison's submissions do not demonstrate that project such as the Dense Pack project are frequent, inexpensive, or done for the purpose of maintaining the facility in its present condition. Instead, the source relies on two principal arguments: (1) It claims that this project is less significant in scope than was the activity in question in the 1988 applicability determination for the Wisconsin Electric Power Company (WEPCO); and (2) it alleges that EPA has interpreted the exclusion for routine activity expansively to exempt all projects that do not increase a unit's emission rate. EPA rejects both of these arguments, the former because both EPA and the U.S. Court of Appeals for the Seventh Circuit viewed WEPCO's activity as "far from" routine and thus this attempted comparison to WEPCO is unsuitable, and the latter because it is demonstrably incorrect. The attached analysis addresses these points in significant detail.

When nonroutine physical or operational changes significantly increase emissions to the atmosphere, they are properly characterized as major modifications and are subject to the PSD program. In general, a physical change in the nature of the Dense Pack project, which provides for

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the more economical production of electricity, would be expected to result in the increased utilization of the affected units, and thus, increased emissions. Notwithstanding the fact the Monroe units may be high on the dispatch order, the Dense Pack project would allow Detroit Edison to produce electricity more cheaply per unit of output, thereby creating an incentive to run Units 1 and 4 above current levels. Even a small increase over current normal levels in the utilization of the affected units would result in a significant increase in actual emissions of criteria pollutants. For example, in 1997, at the Monroe facility Unit 1 emitted approximately 14,000 tons of nitrogen oxides (NO_x) and 41,000 tons of sulfur dioxide (SO_2), and Unit 2 emitted 12,000 tons of NO_x and 35,000 tons of SO_2. Based on this information, if a one to five percent increase in operation were to result from the Dense Pack project, increases on the order of 160-800 tons of NO_x and 400-2000 tons of SO_2 would occur.

Detroit Edison, however, maintains that emissions will not increase as a result of the Dense Pack project. Specifically, the company contends that representative actual annual emissions following the change will not be greater than its pre-change actual emissions, because the Dense Pack upgrade will not result in increased utilization of the units. As you are aware, the PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a nonroutine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change if the source submits information for 5 years following the change to confirm its pre-change projection. In projecting post-change

emissions, Detroit Edison does not have to include that portion of the unit's emissions which could have been accommodated before the change and is unrelated to the change, such as demand growth.

Under the WEPCO rule, Detroit Edison must compute baseline actual emissions and must project the future actual emissions from the modified unit for the 2-year period after the physical change (or another 2-year period that is more representative of normal operation in the unit's modified state). As noted above, Detroit Edison has not provided these figures to verify its projection of no increase in actual emissions, and should submit them to the Michigan Department of Environmental Quality prior to beginning construction. In addition, Detroit Edison must maintain and submit to the permitting agency on an annual basis for a period of at least 5 years (or a longer period not to exceed 10 years, if such a period is more representative of the modified unit's normal post-change operations) from the date the units at the Monroe Plant resume regular operation, information demonstrating that the renovation did not result in a significant emissions increase. If Detroit Edison fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased as a consequence of the change, it will be required to obtain a PSD permit for the Dense Pack project.

Finally, regardless of whether PSD review is triggered due to the Dense Pack project, Detroit Edison must meet all other applicable federal, state, and local air pollution requirements.

This determination will be final in 30 days unless, during that time, Detroit Edison seeks to confer with or appeal to

the Administrator or her designee regarding it. If you have any questions regarding this determination, please contact Laura Hartman, Environmental Engineer, at (312) 353-5703, or Jane Woolums, Associate Regional Counsel, at (312) 886-6720.

Sincerely,

/s/ original signed by
Francis X. Lyons
Francis X. Lyons
Regional Administrator

Enclosure

EXHIBIT 116

**BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL
PROTECTION AGENCY**

IN THE MATTER OF MONROE ELECTRIC GENERATING PLANT ENTERGY LOUISIANA, INC. PROPOSED OPERATING PERMIT Proposed by the Louisiana Department of Environmental Quality	PETITION NO. 6-99-2 ORDER RESPONDING TO PETITIONER'S REQUEST THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF A STATE OPERATING PERMIT

ORDER PARTIALLY GRANTING AND PARTIALLY DENYING PETITION FOR OBJECTION TO PERMIT

On February 9, 1999, Ms. Merrijane Yerger, Managing Director of the Citizens for Clean Air & Water ("CCAW" or "Petitioner"), petitioned the Environmental Protection Agency ("EPA"), pursuant to section 505(b) of the Clean Air Act ("CAA" or "the Act"), to object to issuance of a proposed State operating permit to Entergy Louisiana, Inc.'s Monroe Electric Generating Plant in Monroe, Louisiana ("Monroe plant"). The proposed operating permit for the Monroe plant was proposed for issuance by the Louisiana Department of Environmental Quality ("LDEQ") pursuant to title V of the Act, CAA §§ 501-507, the federal implementing regulations, 40 CFR Part 70, and the State of Louisiana regulations, Louisiana Administrative Code ("L. A.C."), Title 33, Part III, Chapter 5, sections 507 *et seq.*

Petitioner has requested that EPA review, investigate, and make an administrative determination on the entire

matter of the proposed operating permit and planned restart of the Monroe plant, pursuant to section 505(b) of the Act and 40 CFR § 70.8(c). Petitioner alleges that the proposed operating permit is not in compliance with applicable requirements of the Act including Prevention of Significant Deterioration ("PSD") permitting requirements and New Source Performance Standards ("NSPS"). Petitioner also alleges that Entergy's operating permit application fails to adequately demonstrate compliance with hazardous waste disposal requirements under the Resource Conservation and Recovery Act ("RCRA").

* * *

condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or 40 CFR 51.166." 40 CFR § 51.166(b)(2)(iii)(f); *see also* L.A.C. 33:III.509(B).

The purpose of this "increase in hours" exception was to avoid undue disruption by allowing routine increases in production during the normal course of business in order to respond to market conditions. In the preamble to the PSD rulemaking, EPA explained:

> While EPA has concluded that as a general rule Congress intended any significant net increase in such emissions to undergo PSD or nonattainment review, it is also convinced that Congress could not have intended a company to have to get an NSR permit before it could lawfully change hours or rate of operation. Plainly, such a requirement would severely and unduly hamper the ability of any company to take advantage of favorable market conditions.

45 *Fed. Reg.* 52676, 52704 (Aug. 7, 1980). The court in *WEPCO* explained further, "This exclusion . . . was provided to allow facilities to take advantage of fluctuating market conditions, not construction or modification." 893 F. 2d at 916 n. 11.

Analysis of whether restart of a facility constitutes a mere increase in the hours of operation or production rate must consider whether the proposed activity is of the kind intended to be covered by the provision. Specifically, EPA will look at whether the proposed change requires enhanced flexibility to avoid hampering a company's ability to respond to market fluctuations. In general, reactivation after long periods of shutdown, though obviously motivated by long-term changes in the market, is not a response to the same type of market fluctuations and does not merit the same permitting flexibility envisioned by the regulations.

Restart of a long-dormant facility also may not be entitled to coverage under the "increase in hours" exemption if it would disturb a prior assessment of the environmental impact of the source. In the preamble for the 1980 PSD rulemaking, after expressing its belief that Congress intended to allow certain facilities flexibility to respond to market fluctuations, EPA

* * *

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA,	)	
Plaintiff,	)	
v.	)	CIVIL NO. 1:00CV1262
DUKE ENERGY CORPORATION,	)	
Defendant.	)	

EXHIBITS IN SUPPORT OF UNITED STATES RESPONSE TO DUKE'S MOTION FOR SUMMARY JUDGMENT

(Filed Mar. 31, 2003)

* * *

EXHIBIT 139

USA, et al. vs. Duke Energy Corporation 1:00 CV 1262
Laura Butler 12/10/2002

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA
Civil Action No. 1:00 CV 1262

UNITED STATES OF AMERICA,
Plaintiff,
v.
ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP
Plaintiff-Intervenors
v.
DUKE ENERGY CORPORATION
Defendant.

DEPOSITION OF LAURA BUTLER
(Taken on behalf of the Plaintiff)
Raleigh, North Carolina
December 10, 2002

* * *

[15] Q. Is it something that you actively encourage? Trying to get a sense of your working relationship with the sources.

A. Well, we have a good relationship with the sources, but I don't know how to answer your question. We don't advertise that we encourage it, but we do have conversations with somebody representing them.

Q. So in general if – strike that. When we were speaking before about a modification for PSD purposes, what sorts of things are you talking about when you say a modification for PSD purposes?

A. Basically I don't want to be – really would be better to look at the documents that define it, because I wouldn't want to be misquoted or misquote the documents. There are books that talk about this.

Q. Generally?

A. Changes that would basically increase emissions or change in a method of operation. Now the technical staff can give much more detail than that, and that would be preferable.

Q. Is it the sources' responsibility to come in for a permit or is the burden on Air Quality section to identify modifications?

A. The facility should be – would be required to get a permit modification if one has occurred, if a modification [16] has occurred that would trigger a permit action.

Q. Is it Air Quality section's burden to go out and identify those types of modification or does the Air Quality section rely on the facilities?

MR. COTTINGHAM: Object to the form. You can go ahead.

THE WITNESS: Could you repeat that?

Q. Is the burden on – sorry. Is it the responsibility of the Air Quality section to go out and affirmatively identify those modifications?

MR. COTTINGHAM: Object to the form.

THE WITNESS: We don't have the manpower to do that.

* * *

EXHIBIT 140

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA
Civil Action No. 1:00 CV 1262

UNITED STATES OF AMERICA,
Plaintiff,
v.
ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP
Plaintiff-Intervenors
v.
DUKE ENERGY CORPORATION
Defendant.

DEPOSITION OF MICHAEL PARKIN
(Taken on behalf of the Plaintiff)
Raleigh, North Carolina
December 10, 2002

* * *

[9] Q. During that time period did you ever receive PSD applications for changes being made to existing sources?

A. At the time I was environmental Engineer I, I don't recall ever reviewing actually a PSD permit application.

Q. I'm going to have you walk me through a typical inspection. When would the first contact with the facility

be made? Would it be made before the inspection or the day of the inspection?

A. At that time I would say I would show up with no prior contact.

Q. Where would you go when you got to the facility?

A. Usually to a reception office and then ask for the c ıct at that point.

Q. Once you met up with the contact, what would you to next?

A. I would inform the contact the reason I was there, I would show them a copy of the air permit and say I want to go through and look at the sources on your air permit.

Q. How would you look at the sources on the air permit, what would you do? Would you physically go see them?

A. Yeah, we would walk through the facility, look at the sources and associated control equipment as well.

Q. What were you looking for? What would you be looking for when you walk through a facility?

A. Some things would be operating data that had – just [10] looking to see if everything appeared to be functioning properly, also if there were any new sources that weren't on the permit as we walked through the facility.

Q. Anything else?

A. That would be pretty much the extent of it.

Q. Okay. The first thing you said is you would look for operating data I believe. What did you mean by operating data?

A. Well, with Duke, for example, it would be precipitator data, voltages, spark rates, that kind of thing. The other operating data may include, I don't recall, but generally speaking what boilers are operating at and what their output steam load, for example. They have passivity monitors. We check that type of data.

Q. You also said that at the inspection you made sure that the units were functioning properly; is that right, is that what you said? Okay. What did you mean by that?

A. One might be as simple as looking at the stack and see visually if you see any visible emissions that could be control devices or just see if there's physical problems such as dust leaking out of places or things like that.

Q. And you also said you would look to see if there's new sources?

A. Yes.

Q. And could you explain what you meant by that?

[11] A. Just going through a plant and if there's something shows up there that I see that's essentially not on the air permit, if it is not described on the air permit then I would look to see what it was and see if it might require air permitting.

Q. And what are some examples of what would be a new source at a utility that would strike that kind of questioning from you?

A. Perhaps, well, a boiler for example, or even storage silo or a bag filter or something like that that they might put up, something of that nature.

Q. If there was a new piece of equipment put inside the boiler, would that raise those types of questions for you all during the inspection?

MR. COTTINGHAM: Object to the form. You can answer that if you can.

THE WITNESS: A new piece of equipment inside the boiler. I would have to, I mean it might be hard for me to detect a new piece of equipment inside the boiler so I don't know.

Q. After you walk around through the facility, what would you do next for an inspection?

A. After done normally have an exit interview, perhaps an inspection, some type of file review or if there's any paperwork to look at.

[12] Q. What's involved with the exit interview? You said perhaps, so I wasn't sure if that's a normal but if you could just explain if there is an exit interview, what would be involved?

A. If there were any problems I found I would discuss that with them or if I had intended on issuing some sort of notice of violation I would discuss that with them. If I didn't intend on it, I would say okay, that's it.

Q. You said sometimes you do a file review. What would that involve?

A. It is a little – I can answer it more too to the extent how I do it now verses. I mean this is of course many years ago.

Q. Right.

A. Obviously much more paperwork involved in what I. do now.

Q. How about when you were an Environmental Engineer I? What did you do?

A. The only thing I can, with utility perhaps looking at the – discussing, have some discussion of their malfunction abatement plan and coal sampling or whatever they use to show compliance with say sulphur standards or something like that.

Q. Back to when you're walking through the facility, if a unit is shut down, how would that affect your [13] inspection?

A. I would say at that time if it was shut down pretty much moved on to the operating units.

Q. As part of this inspection, did you ever back when you were an Environmental Engineer I, did you ever ask about all the work that had been done to the facility since last inspection?

MR. COTTINGHAM: Object to the form.

THE WITNESS: No.

Q. Would sources ever provide you documentation of all the work that had been performed at the facility since last inspection when you were an Environmental Engineer I?

A. No.

Q. Mr. Parkin, I am now handing you what I have marked as Plaintiff's Exhibit 694. You can take your time to look it over and let me know when you're ready for questioning.

A. Okay.

Q. First of all, could you identify for the record what is Exhibit 694?

A. It is an inspection report at Duke Power Cliffside steam station for the inspection that took place on August 26, 1992.

Q. Were you present for this inspection?

A. Yes.

Q. Did you write this inspection report?

[14] A. Yes, I did.

Q. Do you remember this inspection?

A. Specifically, no, I don't remember, it.

Q. Besides Cliffside were there any other Duke facilities that you inspected?

A. No.

Q. During what time frame have you inspected Cliffside?

A. This may have been the – this I believe was the – may have been my first compliance inspection at the facility. I don't know that for sure but this would have

been in the neighborhood of when it would have been, and I continue to inspect them today.

Q. When you were just identifying this you called it a compliance inspection. Why did you use that terminology?

A. Maybe because I think of things in terms of the new EPA compliance monitoring strategy. I don't know. We do inspections to evaluate compliance. I guess that's why.

Q. Compliance with what?

A. Their air permit applicable regulations.

Q. When you inspected Cliffside around this time frame, do you remember seeing work being done to the units?

(Off-the-record discussion.)

(Interruption for technical problems).

THE WITNESS: Are we preceding at this point?

[15] MR. BERNSTEIN: Do you remember the question?

THE WITNESS: Yes, about work being done. I don't specifically remember August 26, but during this time period I recall going there and work was being done in the areas of units 1 through 4.

Q. Did you have any discussions about this work?

A. I don't recall.

Q. Did you ever discuss PSD with anybody at Duke about this?

A. No, I did not.

Q. Besides seeing the work, did you gain any other information about what work was being done?

A. There was no detail. My understanding that they were, the units had been out of service and they were doing this work in preparation to bring them back online.

Q. How did you get that understanding?

A. I'm sure there was at least some conversation as to, you know, generally as to what was going on. But as far as specifics, I couldn't tell you.

Q. Did you ever do an evaluation for possible changes in capacity due to the work that was being done?

A. No, I did not.

Q. How about a – did you ever to do an evaluation for changes in efficiency?

A. No.

[16] Q. For possible changes in capacity utilization?

A. No.

Q. Did you ever ask them how much the work they were doing cost?

A. No, I did not.

Q. Did you ever ask them how frequent they have to replace the components that they were replacing, if you saw components being replaced?

A. No, I did not.

Q. Did you ever discuss the nature of the work?

A. Not in any detail.

Q. Did you discuss the extent of the work?

A. No.

Q. Did you discuss the purpose of the work?

A. Only to the extent I knew it was part of bringing these units back online.

Q. Did you evaluate the work you saw for PSD applicability?

A. No.

Q. Okay, focusing on Exhibit 694, do you see Number 6, the last sentence at the bottom of that exhibit?

A. Yes.

Q. What does that sentence mean in relation to PSD regulations?

A. Nothing. That regulation is not addressed in that.

[17] Q. Are other regulations addressed in that statement?

A. Pardon?

Q. Are other regulations addressed in that?

A. Yeah, the ones specifically listed on there. But that was, like I said, that's to the best of my knowledge they were in compliance and I wouldn't call it a definitive statement of compliance either, at least based – I did not see anything on the inspection that would lead me to believe they were out of compliance anyway with those regulations listed.

Q. But this wasn't even meant to be a definitive statement that they were in compliance with these regulations?

MR. COTTINGHAM: Object to the form.

BY MS. BEHLES:

Q. Is that what you just stated?

A. I cannot just by looking at it definitively say they were in compliance.

Q. And when you say in compliance, you mean with the regulations listed on Number 6; is that right?

A. That's correct, with the possible exception of say the physical regulation which I can look at and make an evaluation of.

Q. Can you look at a boiler and make a PSD evaluation as an inspector?

[18] MR. COTTINGHAM: Object to the form.

THE WITNESS: No.

Q. Why not?

A. It is just there is not enough information to. I mean, it requires a lot of, I would say, document review of files and documents and things like that to make a PSD evaluation.

Q. Earlier you mentioned that you inspect a large number of industries; is that right?

A. Yes, that's correct.

Q. Is that true for other inspectors?

A. Yes.

* * *

[28]Q. Have you always had a good relationship with the people at Cliffside?

A. Yes.

Q. Who do you report to at your regional office?

A. Paul Mueller.

Q. Is he the regional supervisor?

A. Yes, that's correct.

Q. Who did you report to in 1992 when you did this first inspection that's marked indicated by Exhibit 694?

A. That would also be Paul Mueller.

Q. Has he been the regional supervisor the entire time?

A. Yes.

Q. When you go to a facility like Cliffside to do an inspection, do you generally show up without any prior contact?

A. At that time, yes.

Q. And by "that time" you mean of the '92, '93 time frame?

A. Yes.

Q. And do you now more frequently notify them you're coming?

A. More frequently now. That's across the board just [29] records review we do and we need appropriate personnel there to be able to do it.

Q. The main reason you started notifying facilities that you're coming is so that they can get all the records together you want to look at and have somebody there to help you go through them?

A. Yes, exactly.

Q. When you do an inspection, do they make all the records available to you that you want to look at?

A. Yes.

Q. If you called Cliffside in advance or show up by surprise and say I want to look at all the records on this subject they make them available to you?

A. Yes.

MS. BEHLES: Object to form.

Q. You were asking questions or answering questions of the lawyer about how to evaluate PSD applicability, and you said it would take a lot of documents review but the documents you would review, and if you wanted to and needed to do that, would be documents that they would have to make available to you?

MS. BEHLES: Object to form.

Q. Correct?

A. Yes.

Q. When you go through your inspection, and let's just [30] focus now on Cliffside, the Duke Energy facility

as opposed to something general. Let's be specific about that. When you go through those and do inspections there, if boilers are shut down that's actually a time when you can go inside the boiler if you wanted to do that, isn't it?

A. I couldn't answer that question.

Q. Well, you don't go inside them if they are operating?

A. Oh, certainly no.

Q. So if there was any time you wanted to go inside them it would have to be when they were shut down?

A. It would be when they were shut down, but whole set of issues there.

Q. You're just saying – are you saying you've never actually done that?

A. No, I have not.

Q. Are you saying there are a whole set of issues? Is there any reason why you couldn't have done that if that's what you, wanted to do?

A. There may be as far as confined space entry and that kind of thing. I don't know what sort of OSHA regulations might apply in that scenario.

Q. But assuming you got all the correct safety training and had the right equipment and had somebody there to guide you, you don't know of any reason why you couldn't [31] go?

A. Conceivably I could.

MS. BEHLES: Object to form.

Q. You said in the '92, '93 time frame some of the boilers at Cliffside were shut down. Do you remember which ones they were?

A. Couldn't tell you specifically unless it is mentioned in the record.

Q. This first exhibit says Units 3 and 4 went offline, and I'm reading paragraph 2 of Exhibit 694, says Units 3 and 4 went offline and remained offline at the time of the inspection. And you said you saw the work being done on some of the units at some time, and I just want to be more specific. Did you see work being done, at Units 3 and 4 at the time of this inspection in 1992?

A. Do not recall.

Q. But you do recall see being work done on those units?

A. Yes, there are four boilers right there together and there was work being done in that area. I can't recall specifically which boilers were being worked on when I was there.

Q. Just so we will all understand, Cliffside 5 is a large unit on one side of the river, Cliffside 1 through 4 are smaller units that are on the opposite side of the river?

[32] A. I think they are on the same side of the river, but –

Q. I thought they were on different sides.

A. I would say different sides of the large coal storage pile there.

Q. Okay, close enough. So you can go to Cliffside 5 and then takes a little time to get over to the other?

A. Yes.

Q. Cliffside 1 through 4. But you said that you knew that work was being done on Cliffside Units 1 through 4 in the '92 '93, '94 time frame when you were going –

A. Yes.

Q. And there was nothing to keep you from going to look and see exactly what that work was, was there?

MS. BEHLES: Object to form.

THE WITNESS: No.

Q. In fact you saw the work being done, didn't you?

A. That's correct.

Q. Did you see parts of the boiler disassembled and large components being replaced in the boilers?

A. I could recall seeing parts laying around. I don't remember specifically anything else other than there was, there was quite a bit of activity there.

Q. And this is on Units I through 4?

A. Yeah, some of them. As I mentioned I don't [33] specifically remember which ones.

Q. If you saw something that you thought might trigger PSD, then your normal process was to, I think you said, to follow up or investigate it further; is that right?

A. That's correct.

Q. And if you actually found something that you thought constituted a violation, you could issue a notice of violation or an NOV, couldn't you?

MS. BEHLES: Object to form.

A. That's correct.

Q. In fact you issued an NOV at Cliffside, haven't you?

A. I don't recall if I have or not.

Q. But, you know that's something you could do?

A. Yes.

Q. Now when you prepare your inspection reports, has Mr. Mueller reviewed the inspection reports?

A. He's reviewed some of them. I would not know if he reviewed these reports specifically.

* * *

[36] Q. So following up what we said earlier, when new people came on board at Cliffside for Duke Energy you would go and get to know them?

A. Yes.

Q. And then at the same time you inspected Units 1 through 4 it looks like. Just looking at the last sentence of that paragraph?

A. Yes.

Q. Now turn to the second page of that exhibit and there's a paragraph which starts near the top right after the list of people of Kim Kelley, Mike Hager, Marty Beam

and Sam Sojourner. It says they are expecting to begin firing low Nox burners in Units 3 and 4 in the next few months. Do you see that paragraph?

A. Yes.

Q. And that paragraph ends by saying, "A three week outage is scheduled for Unit 5 during 1997 and eleven week outage is scheduled for Unit 5 in 2001." Do you remember a discussion about what work was going to occur during that time?

A. No, I do not.

Q. And then it says, "Units 1 through 4 we're essentially rebuilt before they were brought online over the past five years." That appears to be information they gave you at the time of this inspection if you didn't know it [37] already?

A. Yeah. I cannot recall.

Q. It was either something that Duke Energy people told you or something you learned from seeing the work or something you learned from looking at the documents or some combination of that? Correct?

A. I think that's a fair assessment.

Q. As of November 12, 1996, if you didn't know earlier you knew then, that Units 1 through 4 had essentially been rebuilt over the past five years, correct?

A. Yes.

MS. BEHLES: Object to form.

Q. Look at the next inspection report. It is March 12, 1997 is the next one in the stack. Do you see that? Has Bates numbers 11795?

A. Yes, I see that.

Q. Let me just direct your attention to the first paragraph. This time it says, "On March 12, 1997 Troy Harrison and I visited the Duke Power plant to observe a source test for particulate emissions from Unit Number 5." Who was Troy Harrison?

A. Troy Harrison is, at least at that time, was an Environmental Technician 5. He was responsible for doing small source inspections and complaint investigations in Rutherford County.

* * *

[41] Q. Did anyone at EPA ever communicate with you about any interest or concern about what had occurred or was occurring at Duke's facility at Cliffside?

A. Not with me.

Q. Look at the last inspection report that's dated July 29, 1999 that ends in Bates numbers 11788. The conclusion of that report in paragraph 6 is, and this is talking about the Cliffside facility, the facility appeared to be operating in compliance with applicable requirements. Correct?

MS. BEHLES: Object to form.

BY MR. COTTINGHAM:

Q. That's what you wrote?

A. That's what the sentence states.

MR. COTTINGHAM: Thank you. That's all the questions I have.

MS. BEHLES: Okay. I just have a few more questions for you.

RE-EXAMINATION

BY MS. BEHLES:

Q. When you said you saw work being done at Cliffside, did you say you saw – how did you know work was being done at Cliffside?

A. There were crews of people. The significant [42] project I guess at that time there wasn't really as a formal a process for initiating the inspection as it become later when I met with the corporate folks and all that. There were times when I showed up to Units 1 through 4 and went to – I didn't go through the reception process in this case. I went and tried first would try to locate Steve Porter in his office; and there are times when I went out to the area where all this work was going on to try and find or see if I could finds someone who knew where he was. And so during this process I was out where Units 1 through 4 were and could see the work going on.

Q. Can you identify all the parts of a boiler by looking at a boiler?

A. Not all the parts but some of the parts, yes.

Q. Are you required to go into boilers that are not, that are shut down?

MR. COTTINGHAM: Object to the form.

THE WITNESS: No.

Q. Are you encouraged to go into boilers that are shut down?

MR. COTTINGHAM: Object to the form.

THE WITNESS: We are basically told not to go into confined spaces.

Q. Referring back to what Mr. Cottingham has identified as Exhibit 901. Can I first have you turn to –

[43] A. 901?

Q. You got it okay?

A. I got it.

Q. To the last page of that exhibit. It ends in the Bates number on the corner is 1790.

A. I got it.

Q. Did you mean for that sentence to be a PSD applicability determination?

MR. COTTINGHAM: Object to the form.

THE WITNESS: When I write that sentence in my mind I'm referring to the list of applicable regulations that are in the air permit.

Q. When you write the sentence why do you include the word "appeared"?

A. As I mentioned before, in the business of air quality, without doing rather extensive and complex testing you really can't make definitive statements as to whether a facility is in compliance. So I would not write and guarantee that everything was in compliance just from looking at it.

Q. When you were discussing the file review that you do in inspections, do you perform that file review as part of inspections to determine if boiler rehabilitation work triggers PSD?

MR. COTTINGHAM: Object to the form.

[44] THE WITNESS: No.

Q. And why not?

A. This is the context of now or in 1992 or '93?

Q. First let's start with 1992-93 and then we can discuss now.

A. One thing, there's probably not much in the files on what was done. And I would say as far as really to modifications at the facility are normally reviewed in the context of an air permit application. And at that time I guess I just didn't think to inquire more about what was going on.

Q. Do you know whether or not if you – well, strike that. And what do you do now? When we were talking the file review. Is it any different now?

A. In what way?

Q. Do you perform that file review as the file review that you perform as part of inspections, do you do that to determine if boiler rehabilitation work triggers PSD?

MR. COTTINGHAM: Object to the form.

THE WITNESS: I would say now if I was looking at a similar or project for somebody that was rebuilding the first, first thing that would pop into my head is get information on how much it was costing and

whether emissions, there would be the bottlenecking quote in any way or something of that nature.

[45] Q. How long has that been your understanding or your practice?

A. I couldn't state specifically. I was probably more regulatorally aware of the NSPS requirements as far as reconstruction if I recall around '94 or so. That's just guessing though.

Q. How about for PSD requirements? Would you perform a file review as part of your inspection to determine if that boiler work triggered PSD?

A. As part –

MR. COTTINGHAM: Objection to form.

THE WITNESS: As part of inspection, no.

Q. Would you do that currently?

MR. COTTINGHAM: Object to the form.

THE WITNESS: That's a difficult question. It would have to be the scenario. I might.

Q. If I could have you look at Exhibit 694, the first page of Exhibit 901?

A. Which one are we talking again? 8-26-92.

Q. Yes.

A. Okay.

Q. And in reference to paragraph number 5, was it Duke's duty or obligation to tell about that violation?

MR. COTTINGHAM: Object to the form.

THE WITNESS: In essence, yes, because they are [46] required to report their annual average capacities, which is reviewed under in the stationery source compliance branch as reports.

Q. Is it the source's duties to go to the state for a PSD applicability determination?

MR. COTTINGHAM: Object to the form.

THE WITNESS: It is a difficult question. It would be my opinion if they suspect there is a PSD issue it is their duty to come to the state.

Q. Have you ever given any indication to Duke that the boiler work that you saw did not trigger PSD?

MR. COTTINGHAM: Object to the form.

A. No.

MS. BEHLES: I think that's all. Thank, you for your time.

RE-EXAMINATION

BY MR. COTTINGHAM:

Q. Mr. Parkin, you never went back after you came to understand that you might look at cost and other factors in connection with work that had been performed, you never went back and tried to collect that information on Cliffside 1 through 4, did you?

A. No, I did not.

MR. COTTINGHAM: Thank you.

* * *

EXHIBIT 141

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA
Civil Action No. 1:00 CV 1262

UNITED STATES OF AMERICA,
Plaintiff,
v.
ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP
Plaintiff-Intervenors
v.
DUKE ENERGY CORPORATION
Defendant.

DEPOSITION OF MICHAEL LANDIS
(Taken on behalf of the Defendant)
Raleigh, North Carolina
December 11, 2002

* * *

[15] Q. Did the people you had contact with at Duke Energy during all the years you inspected there, did they always seem interested and sincerely interested in complying with environmental regulations and rules?

MS. BEHLES: Object to form.

THE WITNESS: To the best I could tell, yes. Like I say, I never have any problem getting the information I needed. And generally the information I needed was

for compliance issues anyway, and it was always made available.

Q. I'm going to show you what we marked as Exhibit 902 and those are inspection reports for the Riverbend facility that you prepared?

A. Okay.

* * *

[17] A. Here is another one too by Therman. It is 001326, 001327 and 28. I can tell my writing. It's bad. Okay, yeah, all these except for the things by Therman Horne are mine, yes, that's correct.

Q. And they start – the first one is dated August 16, 1978?

A. That's correct.

Q. And the last one is dated, looks like, February 20, 1991.

A. Yes, it appears to be 1991, yes.

Q. Let me ask you to look at the one that's dated – we will start here at June 5, 1989?

A. Do you have a page?

Q. It has a Bates stamp number of 7129 at the bottom and since it is a 1989 it is near the back.

A. What's the date of the thing again?

Q. June 5, 1989. You signed it on June 14?

A. June 5, 1989, yes, I'm at the one.

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Q. That's an inspection that you conducted on June 5, 1989 at the Riverbend facility?

A. Yes, sir.

Q. It says, "This facility is an electricity generating plant. There are four boilers at the plants, 6, 7, 8 and 9." Is that the way you remember Riverbend?

A. Yes, sir.

[18] Q. And then you say, "only boiler number 8 was in operation during this inspection."

A. Uh-hum.

Q. "The other three boilers are in the plant modernization program."

A. Yes, sir.

Q. Tell us what you saw or knew about the Duke Energy plant modernization program?

A. I really don't recall what I saw. I just really don't remember a whole lot about – my understanding of the plant modernization program was that Duke Power was to increase, was trying to increase the efficiency of the boilers. And my understanding of that, whether incorrect or correct, my understanding of that was to try to get more generation capacity out of the same amount of coal. And also my understanding was that there would be no increase in BTU heat input. It was just a matter of however you get more power, I don't know. But that was my understanding of the plant modernization program.

Q. Did you have an understanding that that program had been approved in some way by headquarters in Raleigh?

A. Well, I hadn't really thought about that until during the interviews Keith mentioned that there was headquarters that said that was, headquarters being down here in Raleigh, and the division or the department had said [19] that that was okay, and that said it was okay to do that. That's about all I know about that memo. I don't recall seeing the memo specifically. And so and I'm sure Keith, and I don't recall Keith ever saying it but I'm sure he did at some time, that said it was okay. And I never gave it any more thought.

Q. Keith Overcash was your supervisor at the time of this inspection?

A. Yes, sir. He was regional supervisor at the time yes, sir.

Q. And now is Director of Division of Air Quality?

A. Yes, sir.

Q. When you saw the plant modernization work at the three boilers, did you see activity and see tubes and parts on the ground or around or being installed?

A. Yes. There was a lot of stuff on the ground. I think in part 2 I think they were trying to get rid of asbestos at the same time. It was kind of concurrent sort of thing. There was a lot of stuff laying around on the floors, tubes and things. But like I say, once in my impression was it was okay to do that, I really didn't pay a lot of attention to it. It wasn't something I needed to be concerned about.

* * *

[21] Q. But at least appears from these inspection reports that Mr. Cheng's the one who did the inspections at Riverbend during that time?

A. Like I say, all I can tell you, that's his signature and at least that's the way I recall his signature.

Q. And he's dated each inspection beside his signature?

A. Yes.

Q. Let me just ask you to look at the first one which is November 24, 1986 in the first paragraph. It says, "None of the units of this power plant were in operation during my visit. Unit Number 6 and 7 had been put into the plant modernization project in 1989." Is that what he wrote then?

A. That's what it says, yes, sir.

Q. And if you look at the very next report, the one dated May 4, 1987, he dated it when he signed it May 13, 1987. Again in paragraph 1 it says, "Units Number 6 and 7 have been put into the plant modernization plan until 1991 and 1992."

A. That's what it says.

Q. The next report, which is dated looks like June 5, 1987 is when he signed it. In the second paragraph he says, [22] "Units 6 and 7 are currently in the plant modernization program and not expected to be in operation until 1991 and 1992."

A. That's what it says.

Q. And the next report, which looks like February 25, 1988, he says there, "Units 4, 6 and 7 have been put into the plant modernization plan until 1991 and 1992."

A. That's what it says.

Q. And then the final report by Mr. Cheng dated October 12, 1988 says "Units 4, 5 and 7 have been put into the plant modernization plan until 1991, '92."

A. That's what it says.

Q. Look also just one more minute at his reports. All of them have a paragraph that conclude with a sentence that says either the facility is considered to be in compliance with the applicable regulations or it says in some cases "PSD NSR, and NESHAP do not apply."

MS. BEHLES: Object to the form.

THE WITNESS: That's what it says.

Q. You also inspected at the Bucks station I think we said?

A. Yes, sir.

* * *

[33] EXAMINATION

BY MS. BEHLES:

Q. Mr. Landis, my name is Deborah Behles. I am hear representing the Department of Justice. I have a few follow up questions for you this morning.

A. Yes, ma'am.

Q. When you would go on inspections of Duke facilities, did you ever talk about PSD issues?

A. Not that I recall, no, ma'am.

Q. Did Duke ever talk about PSD issues on these inspections?

A. Not that I recall, no, ma'am.

Q. Do you know whether any other inspectors ever discussed PSD issues on their inspections?

A. No, I don't know whether they did or not.

Q. Do you know what happened on inspections that you did not attend such as the ones by – the ones that we have that you've seen in these exhibits?

A. No, I wouldn't know. The only thing I would know is what was in the report itself. That's the only thing I could tell you because it is generally what you wrote your report from, the notes that you took during the inspection itself.

Q. Did you ever do any emission calculations when you went on an inspection?

[34] A. No.

Q. Did you ever inquire about the cost of the work that was being done when you went on an inspection?

A. No, I did not. I don't recall doing that. I may have asked a question but I just don't recall that.

Q. Did you ever ask about the frequency of the components, of how frequent the components were replaced in the boiler that were being worked on?

A. No, ma'am, I didn't.

Q. Did you ever ask about the nature of the work in your inspections?

A. I may have talked about it to like during the stack test, you're standing up on the roof and just watching the test go on and you just talk; and I may have talked with plant people about what they were doing and that sort of thing. But that was just kind of general conversation with maybe one of the welders or something, just to have something to talk about. Other than that, that's about all I remember.

Q. Did you ever do any netting analysis on any of these inspections?

A. No, ma'am, I did not.

Q. Earlier you mentioned that on these inspections your contact was generally the precipitator, is a precipitator engineer?

A. He would have been one of the contacts, one of the [35] contacts. Generally when we did an inspection we would say hello to the plant manager, and then one of the plant engineers, and generally the engineer that was assigned to supervise the operation of the precipitators, would go along with us because we eventually wind up there anyway. Rather than trying to run him down 30 minutes after we started, it is easier to take him with us. And that's generally – and then when we have a closing interview and let the plant manager know if we observed any problems and what those problems might have been. And if not, we say everything looked like it was okay to us. That's kind of a quick overview of an inspection.

Q. On the inspections that you went on that Mr. Cottingham showed you in these exhibits up in front of

you, was the focus of these inspections to look at particulate matter related issues?

MR. COTTINGHAM: Object to the form.

THE WITNESS: Well, like I said, a lot of these are stack test observations. But generally the inspections, whenever we would do inspection, generally yes, I would say that it was related to particulate, because ESP doesn't control sulphur dioxide or gaseous emissions. And that's what we looked at in general was to make sure the operation of the precipitators was within what they should have been. And we looked at visible emissions, too, and that again is in [36] general of particulate emissions.

Q. You mentioned that you saw some work being done at some of the inspections that you went on. Did you know the specifics of all the work that was being done?

A. No, I did not know the specifics, un-unh.

Q. When you're on an inspection, can you determine whether a facility is in compliance with the visible emissions limit by looking at the stack?

A. Yes, sir. Yes, ma'am, I'm sorry. I apologize. Yes, ma'am. I'm certified to read visible emissions, and I was during the time that I was performing these inspections as well.

Q. Can you determine if a boiler is in compliance with PSD by looking at the boiler?

A. By – can you define that a little more? Do you mean by just – I really don't understand what you mean. If you could define that a little better for me, appreciate it.

Q. By just looking at the boiler and the work that is being done, can you determine on an inspection the PSD is triggered?

A. No.

MR. COTTINGHAM: Object to the form.

A. I am sorry. I should have waited. No, you can't.

Q. And why not?

A. PSD is not a regulation that is easy to interpret. [37] You got to do some calculations and that sort of stuff. You got to do a lot of stuff to determine generally whether a facility is subject to PSD or not. And during inspections we didn't do calculations and those kinds of things. During an inspection in general, just from the inspection and looking at a boiler, you couldn't say it is subject to PSD or not.

Q. Earlier when you were talking to Mr. Cottingham you mentioned that you had an understanding of the PMP program, that they were trying to use the same amount of coal to increase the efficiency?

A. That's just my impression. If someone says they are trying to increase the efficiency of a boiler or whatever, I just kind of maybe made an assumption that that's what they were trying to do. I never really talked about it. But it just seemed like you're increasing the efficiency of something that seems like a good idea at least from the surface.

Q. And where did you get that understanding?

A. Oh, just, you know, in talking with the plant people during inspections and asking a few questions

about the PMP program, there was the understanding I got.

Q. Earlier you also mentioned that you thought Keith Overcash had okayed –

A. No, it wasn't Keith. It was I think the Director of Air Quality probably had some input. And this is using [38] Keith's words from the interviews that we had previously. I didn't directly recall that until he started mentioning that and I thought, oh, yeah, that is right. That the department secretary, I don't remember who that was, said that it was okay. And so, like I say, those guys say it's okay, it is fine with me.

Q. What interviews are you referring to?

A. The interviews that we had, I had with – I apologize. I've forgotten your name.

MR. COTTINGHAM: Tom Cottingham.

THE WITNESS: And the other fellow that was on at the Winston-Salem office. That was during the interview and Keith mentioned, Keith was there and he mentioned that particular memo from, I think it is, Paul Williams. I don't remember. But that's the one he mentioned. And I thought, yeah, we wouldn't have said – we would probably questioned it a lot more if we had not had something like that from the departments. And that would have made sense. If you go do an inspection and something is going on like that, you're going to ask a lot of questions. I don't ever recall asking any questions about why are you doing this, that sort of thing. When he said that was – yeah, that made a lot of sense that I didn't ask any questions about what was going on and why they were doing it until – that's the reason I didn't ask those kind of

questions during inspection. Because I would [39] ask those kinds of questions, I would have asked those kinds of questions if something hadn't been cleared or I felt like it was okay.

Q. If I could show you what's been previously marked as Exhibit Number 6. Take your time to look through it and let me know when you're ready for some questions on that exhibit. I just want to note for the record, the copy that I handed him actually had a notation that says "Evans" on the bottom left-hand corner. And that was written by my co-counsel. Not part of the document.

A. Okay. I've read the, I guess it is a, letter to Mr. Helms from Duke Power.

Q. Okay. And can you read the second letter as well?

A. Oh, okay. I'm sorry.

Q. Oh, no.

A. Okay.

Q. Is the correspondence in Exhibit Number 6 the correspondence you were referring to that was discussed during this interview you had with –

A. Well, Keith mentioned this memo. I don't ever recall seeing it. It is kind of one of those things that headquarters says it is okay, and Keith would say it is okay. And I don't recall seeing the memos specifically. I really don't.

Q. But is this Exhibit Number 6 the memo that Keith [40] was referring to?

MR. COTTINGHAM: Object to the form.

THE WITNESS: I would assume it is. That's all I can tell you. I would assume that it is.

Q. Do you know whether Duke ever informed North Carolina about any work being done to the units during the PMP projects after this letter?

MR. COTTINGHAM: Object to the form.

THE WITNESS: I don't know. I really don't.

Q. Do you know whether Ying Pong Cheng ever did a PSD evaluation when he went on inspections?

MR. COTTINGHAM: Object to the form.

THE WITNESS: I am sorry.

MR. COTTINGHAM: That's okay, go ahead.

THE WITNESS: I don't know. You asked if we did one during an inspection?

Q. Uh-hum.

A. Like I said, PSD is too complicated to sit down and do that during an inspection. You have to sit down and do a lot of calculations and that sort of stuff and look at a lot of information to make the determination on PSD. That's not something that we would do in general during an inspection, just too complicated.

MS. BEHLES: I have no further questions.

RE-EXAMINATION

[41] BY MR. COTTINGHAM:

Q. Mr. Landis, if you saw something during an inspection which you thought might trigger PSD, you would then investigate that further outside the inspection period but you would go back to your office and do other things to investigate that further?

A. Well, even during an inspection I don't know that just – what we generally look for is stuff that's not in the permit; and if it is not in the permit, we ask questions about it and we investigate further. And it is really difficult to say when you go out and do an inspection that might be a PSD problem. You say, well, that's unusual and different, but you can't say during the inspection whether PSD applies or not; and you would have to go back and gather more information to make the determination. Just can't do that.

Q. And that was my point. If you see something that raises a question about whether –

A. You do further investigation, that's correct. Yes, sir.

Q. And if you wanted to, with the Duke Energy facilities in particular, if you wanted to find out information like the cost, frequency, nature, extent and purpose of work that you saw going on, there were documents that you could get from Duke Energy and people you could talk [42] to at Duke Energy who would give you that information, correct?

MS. BEHLES: Object to form.

Q. If that's what you wanted to find out?

MS. BEHLES: Objection.

THE WITNESS: Yes. My experience has been if we need more information, we ask for it. And most companies are generally forthcoming in giving us the information we need so we can make a proper determination. And we always – if we don't get enough information the first time, we keep asking until we get the right amount of information to make that determination. We don't want to do a PSD applicability determination without all the information. You got to have all the information to be able to do it right.

Q. That's right. Whenever you asked for information from Duke Energy for purpose, they have always been forthcoming and given it to you?

A. Yes, sir, they have.

MS. BEHLES: I was going to object to form.

THE WITNESS: But yes, they have.

MR. COTTINGHAM: That's all the questions I have.

* * *

EXHIBIT 142

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA
Civil Action No. 1:00 CV 1262

UNITED STATES OF AMERICA,
Plaintiff,
v.
ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP
Plaintiff-Intervenors
v.
DUKE ENERGY CORPORATION
Defendant.

DEPOSITION OF THOMAS McMANUS
(Taken on behalf of the Defendant)
Raleigh, North Carolina
December 11, 2002

* * *

[7] Q. So you've been in Air Quality since '91 or '92?

A. Yes, sir, somewhere in that neighborhood.

Q. Have you been conducting inspections during that entire time you've been in Air Quality?

A. Yes, sir.

Q. And that includes compliance inspections that you've conducted at the Duke facilities at the Allen, Buck, Marshal and Riverbend?

A. Yes, sir, it does.

Q. I'm going to ask you about those inspections in a minute, but first let's talk more generally and just focusing on those Duke Power plants. Do you get to know the Duke employees in the course of doing those inspections?

A. Yes, sir.

Q. And get to know people who supervise the employees [8] at the plants?

A. Yes, sir.

Q. Tell us just in your own words what appears to you to be the attitude of the Duke employees towards complying with environmental rules and regulations.

A. It's been my experience that the environmental coordinators who are located at the site who is responsible for all environmental programs at each plant as well as their supervisor and also their support group have been very open and forthcoming and not only accommodating our inspections but providing answers or information that we had regarding any operations or regarding to air permit at that facility.

Q. Have they always seemed seriously interested in understanding what they had to do to comply with the law?

A. Yes, sir.

MS. BEHLES: Objection to form.

Q. And seriously interested in trying to comply?

MS. BEHLES: Objection to form.

THE WITNESS: Yes.

Q. Have you had occasions when you had to ask them for more information about something or try to get more documents or just more information orally from them?

A. Yes, sir.

Q. Have they always provided you whatever documents and information you asked for?

[9] A. Yes, sir.

Q. Let me ask you something more specific. When you've seen work being performed at Duke facilities and let's talk about work that's maintenance, repair or replacement work, if you wanted more information about the nature or extent or purpose or frequency or cost of that work, is that something that would be available to you from Duke Energy that you could get?

MS. BEHLES: Objection to form.

THE WITNESS: Yes, sir.

Q. I'm going to show you what we marked as Exhibit 909, Mr. McManus. I want you to look at that for a minute and see if those appear to be inspection reports that you signed in connection with inspections at the Duke Power Allen plant starting in 1994 and going through April 19, 2000?

A. I've had this cold a while. These appear to be copies of the inspections and reports that I prepared.

Q. Let me ask you to just look at one first that's dated July 14, 1995. I think it is the third one in the stack. You can take that clip off if it helps you. Is that the July 14, 1995?

A. Yes, sir.

Q. There's a – okay, let me look at that because there are two that date. Look at the next one. There's another one that has the same date. Is that it?

[10] A. Yes, sir, this one.

Q. That's right. That's the one I want to ask you about. I want to focus on the last paragraph of that report. It says, "It should be noted that during this site visit Mr. Don Scroggs of Duke Power company accompanied the writer to observe an unpermitted 110 above ground number 2 oil storage tank." Do you remember that event?

A. Yes, sir.

Q. Tell us what happened there.

A. I remember this issue because we was looking at NSPS subpart KB applicability at that time and we were discussing this issue to determine if it was applicable.

Q. And was this a storage tank that you saw that – to which NSPS might apply?

A. Yes, sir.

Q. And did Duke Energy cooperate fully with you in trying to investigate that issue?

A. Yes, sir. They provided the information that I requested in order to make that determination.

Q. And did you eventually make a determination about whether NSPS applied?

A. Yes, sir, best of my knowledge we did make that determination. I don't remember exactly if it was applicable or not, but we did make that determination because I do recall reviewing that and discussing it at that time with my [11] regional supervisor.

Q. How did this above ground storage tank come to your attention?

A. If I recall correctly, I believe Duke Power brought it to our attention about whether I think through an internal audit, if I recall, some of their own internal environmental audits, the question came up: Is this applicable or not? They brought it to our attention. When I performed our inspection, I went and ahead and looked at it closely and we asked for the information acquired to make that determination.

Q. Is that an example of Duke Power having a concern or question about whether NSPS or regulation applied to something they had at their facility or were doing at their facility and they would raise that with you?

MS. BEHLES: Objection to form.

THE WITNESS: It's been my experience not only this inspection but through my dealings with Duke Power, whether there's been a situation that may lead to a notice of violation or whether it's just been issues that need clarification, that they've always been forthcoming with whatever I have asked for.

* * *

[13] Q. It says here, "Bill Kissel of MRODAQ accompanied me on this inspection." Tell us what MRODAQ stands for?

A. Mooresville Regional Office, Division of Air Quality.

Q. Same type of position you held?

A. Yes, sir. He was an engineer.

Q. And he accompanied the EPA people about a month or six weeks earlier when they went to Allen?

A. Yes, sir, he did.

Q. The report is six pages long. Tell us what you concluded at the end about the compliance status?

MS. BEHLES: Objection to form.

THE WITNESS: Okay. When we perform inspections, whether it is a Title 5, Duke Power or any facility that we have a permit on, after we inspect and review records and everything is considered, our bottom statement is, determines whether we feel like based upon what we reviewed and what we inspected at that time it appeared to be in compliance with all the applicable air quality regulations.

* * *

[18] Q. This, in looking at paragraph 3 where it says "Purpose, purpose of inspection/facility, general." "The purpose of this visit was to conduct a routine air quality compliance inspection."

A. Yes, sir.

Q. Is that one of the, like the others, a general inspection that you conduct?

A. Yes, sir. These are our, like it states there, routine air quality compliance inspections that we do periodically.

Q. This looks like Angela Hall from Mooresville accompanied, you on this inspection?

A. Yes, sir, she did.

Q. And you met with Donna Burrel or is it Burrell?

A. I call her Burrel.

Q. I will too. And she's the environmental coordinator at the Allen plant?

A. Yes, sir.

Q. Has she always been forthcoming and open and honest with you?

A. Donna sticks out particularly well because she is very meticulous and they call her the school teacher because she'll correct everyone's paper before they send them out. They'll let her proofread them. Donna is very meticulous and also I'd like to at this point there's a gentleman on here [19] named Lawson Jenkins. And he is also available and we go into quite in depth and of what they're doing with the ESPs and basically giving me a good education every time I go. Learn a little more each time. Jeff Russell, he is typically there so he can answer anything from the CEMS side or anything along those lines.

Q. Does Duke Power always provide the people to answer any questions you have?

A. Yes, sir. Typically the way they do it now is like for instance, Ms. Burrel, we typically do unannounced inspections; but I will give several days notice because if these folks are not there, there is no use for me to go to the plant and didn't feel like there's nothing that can change in that short of amount of time. But she'll organize it with these folks to work it out so they can be there to answer all my questions, because I do get very detailed in some of these issues. And the other plants, they have these folks available, similar positions at the other plants also so that I can ask questions. And when we go to the plants, I'll even go and typically talk to the operators and ask them questions about what they do and so forth, if they have people readily available. And then there are folks from an operator to whoever is working that I'll just – not unusual for me to stop and ask them question, whether it was just for my knowledge, education or whether I feel like it may be [20] compliance related.

Q. Let me show you one more group, Exhibit 912. Are those inspection reports that you prepared and signed for the Riverbend facility of Duke Power company from March 11, 1994 through June 13, 2000?

A. Yes, sir, these appear to be copies of my inspections performed at Riverbend station.

Q. Let me ask you to look at the last one that's dated June 13, 2000.

A. Okay.

Q. This appears to be one of the – under paragraph 3, the routine air quality compliance inspections?

A. Yes, sir.

Q. And Ms. Carlotta Adams from the Monroe office accompanied you on that inspection?

A. Yes, sir, from the Mooresville office.

Q. I mean from the Mooresville office. And you met with Steve Rutledge at Riverbend plant?

A. Yes, sir.

Q. Has he always been cooperative with you?

A. Yes, sir, he has.

Q. And does he appear to be knowledgeable and interested in complying with Clean Air Act regulations?

MS. BEHLES: Objection to form.

THE WITNESS: Based upon my interaction with him [21] and the questions I asked, he's always been forthcoming and appeared to me to be conscientious about not just air quality but these folks are also responsible for the water, waste and other issues. But yes, sir, he did.

Q. Let's look at your conclusion in paragraph 11 and 12. You say, "During this inspection the facility appeared to be in compliance with applicable air quality regulations with the exception of the following." And then this is the first time I have seen it in any of your reports you refer to the EPA saying that the Riverbend facility is in violation but on schedule is –

MS. BEHLES: Objection to form.

THE WITNESS: And –

Q. Let me ask you first. Was it your conclusion separate from what EPA said that the facility appeared to be in compliance with applicable air quality regulations?

MS. BEHLES: Objection to form.

THE WITNESS: Everything appeared to be in compliance with exception to EPA's concern with the PSD issue.

Q. Tell us what EPA had said to you, if anything about their concern about the PSD issue?

A. I have limited interaction. I am not sure I even talked with any of the EPA folks. This came down through our office, that there was a concern about PSD applicability on [22] rework of some of the units and that came down through our folks.

Q. In all your experience in inspecting units at Duke Power, had EPA ever before this time in 2000 said they had any concern about PSD issues at Duke Power plants?

A. Not during my tenure, no, sir.

MR. COTTINGHAM: Thank you, Mr. McManus. That's all the questions I have.

MS. BEHLES: Can we take about a five-minute break?

VIDEOGRAPHER: Off record. Time is 12:10.

VIDEOGRAPHER: On record. Time is 12:16.

EXAMINATION

BY MS. BEHLES:

Q. Mr. McManus, thank you for coming down today. As I mentioned earlier, my name is Deborah Behles. I am here representing the U.S. Department of Justice.

First of all, in reference to something you were just speaking about to Mr. Cottingham, you were talking about NSPS applicability to some kind of tank. What kind of tank was that?

A. If I remember correctly, I think it was about a hundred, 110,000 gallon number 2 fuel oil storage tank which is typically used for light-off say from a cold start where they use number 2 fuel oil until they get it up to a temperature where they can inject the pulverized coal unit.

* * *

[24] Q. During thse inspections that we have the reports that are marked in Exhibits 909 through 912, did you ever have any discussions about PSD?

A. No, ma'am, not that I recall.

Q. Did Duke ever ask about PSD?

A. Not directly to me that I can recall.

Q. Did you ever do a PSD evaluation on any of these inspections?

MR. COTTINGHAM: Object to the form.

A. No, ma'am. No, ma'am. Those determinations are not made in the field. If there would be a red flag to go up, then of course we start gathering the information to make

BEST AVAILABLE COPY

that determination back at the office or once we reviewed all the information and talked to all the appropriate people.

Q. Would you ever do emissions calculations for PSD purposes in the field?

A. No, ma'am. In compliance we typically do the compliance inspections. That is usually addressed with our permits folks, and also we received the annual air emissions inventory which provides us with their emissions and that data is readily available on the CEMS also.

* * *

[32] Q. Would you say that ESP performance and opacity determinations are the focus of these routine inspections?

MR. COTTINGHAM: Object to the form.

THE WITNESS: That's a big part of the inspection but that's not the total inspection. Total inspection is to look at all air quality related issues at the plant.

Q. In these inspection reports, when you say "this facility appeared to be in compliance with applicable regulations," do you consider this sentence to be a PSD evaluation?

MR. COTTINGHAM: Object to the form.

THE WITNESS: When I write that statement, that is everything to my knowledge that I can think of that would be applicable to that facility. If I thought PSD was an issue, then that would be raised. Like I stated before, if I overlook something, then typically supervisor or other folks that's reviewing these would call that to my attention. But

when I write that statement, based upon my file review, on site inspection and all post inspection work, I only write that statement if I truly feel that this facility is in compliance with all regulations.

Q. Have you ever done a PSD evaluation during an inspection?

A. No, ma'am, I have not.

* * *

EXHIBIT 146

KEY REGULATIONS AND ISSUES IMPACTING
ALTERNATE FUELS, FUEL ADDITIVES,
AND FACILITY MODIFICATIONS
WTH 2/13/95

PREVENTION OF SIGNIFICANT DETERIORATION (PSD).

The federal PSD regulations were designed to prevent additional deterioration of air quality in geographical areas near major emissions sources beyond state-established emission baselines. If a proposed Duke project triggers PSD requirements, the cost of the project would increase substantially for best available emissions control technologies (e. g. scrubbers, baghouses, upgrades ESPs etc.) on the emission source/unit in question.

Exemptions from "major modification" definition:

1) Routine repair, maintenance, and replacement.

2) An alternate fuel or raw material generated from municipal solid waste.

3) An alternate fuel or raw material the source was capable of accomodating before 1/6/75, unless prohibited under a federally enforceable permit condition after 1/6/75.

4) A change in ownership.

5) WEPCO: A pollution control project that is overall "environmentally beneficial" electric utility project, providing . . .

a) no significant net increase in representative, actual, annual emissions of a criteria pollutant (SO2, NOx, particulate, VOC/O3, CO, Fl, Pb, Be, Hg, sulfuric acid mist, plus HCl and chlorinated dioxins and dibenzofurans from municipal waste combustors). Note: The

State/EPA will consider the representative actual annual emissions following the modification to be the average rate in tons/yr of any 2-yr period w/i a 10-yr window following the change, taking into consideration the effect of the change on the hourly emissions rate and on capacity utilization. Any increased capacity utilization unrelated to the change or related to growth and increased electric demand will not be considered in the average rate calculation.

b) will not contribute to national ambient air quality standard violation, visibility impairment, or consume PSD increment.

Source Exemptions:

6) Emissions increases leading to air quality impacts less than de miinimis amounts for CO, NO2, TSP, PM-10, SO2, O3/VOC, Pb, Hg, Be, and Fl, using current EPA-approved dispersion models.

Key Definitions:

Municipal Waste Incinerators/Combustors, as defined in the PSD regulations, are capable of burning >250 tons of refuse/day. Other definitions in the the municipal waste regulations may also apply.

NEW SOURCE PERFORMANCE STANDARDS (NSPS).

The federal NSPS regulations were designed to ensure that new facilities meet more stringent air emissions rate standards and to ensure that existing sources adhere to the same stringent new source standards when they undergo an applicable modification (a physical change or change in method of operation that would increase the

ton/hr emission rate of a pollutant to which a standard applies. If a proposed Duke facility modification triggers NSPS for the major generating units, the cost of the project would be substantially increased to achieve more strignent NSPS emissions rates and for additional monitoring and reporting requirements to document compliance under the new requirements.

The ton/hr emission rate following the change would be compared with ton/hr emission rate 5 years prior to the change (e. g. the modification must not be for the purpose of regaining capacity which has not been maintained over time).

Exemptions from Applicable Modification:

1) Routine maintenance, repair, and replacement. Replacement of entire systems (including aux. and other small boilers even if the replacement is smaller than the the original equipment) is a "reconstruction" and falls under the 50% rule below.

2) An increase in the production rate w/o a capital expenditure.

3) An increase in the hours of operation (note: PSD regs disallow an increase in hr of operation not attributed to increased electric demand.)

4) Use of an alternate fuel or raw material IF the facility was originally designed to accomodate the material (e. g. if the material's use could accomplished under the facility's construction.)

5) Addition or use of a system or device whose primary function is to reduce air pollutants (overall environmental beneficial determination determined at the discretion of EPA).

6) Change in ownership.

Reconstruction. In addition to any consideration of hourly emission rate, any replacement of components of an existing facility that results in a fixed capital cost of the components in excess of 50% of the capital cost to construct a comparablel entirely new facility would trigger NSPS.

MODELING/TALL STACKS ISSUES.

State Toxics

NC and SC air toxics regulations prevent increases in emissions of some 200 listed inorganic and organic toxins from air emissions sources. Facility modifications including use of alternate fuels and fuel additives that increase emissions of any state-listed toxins will require a toxics evaluation. The evaluation may involve

1) an analytical demonstration that the change will offset coal combustion and result in a "net decrease or no increase in each state-listed toxin.

2) Net increases in a particular toxin will require a model demonstration that the health based allowable abmient limit (AAL) can be met at the property line.

Note: Combustion of materials that are higher in arsenic than coal should be avoided at all facilities but Belews Creek and Cliffside 5, due to short stacks and inadequate poor dispersion. Otherwise, the facility could be subjected to toxics controls or erection of taller stacks.

Sulfur Dioxide

NC and SC regulations have required a modeling demonstration of compliance with the national ambient air quality standards (NAAQS) for SO_2. Due to the short stacks at all facilities but Belews Creek, modeling of SO_2 remains an unresolved issue. We are currently demonstrating compliance for all facilities via monitoring at Marshall and Riverbend.

Note: Any modifications (including alternate fuels or additives) that increase sulfur dioxide emissions, would raise the SO_2 dispersion modeling issue, triggering a requirement to build taller stacks, load reductions, or a lower SO_2 emissions rate. Also, modifications that negatively impact SO2 dispersion, (eg. decreased exit gas temperature, or decreased velocity) would raise the SO_2 modeling issue for coal-fired facilities other than Belews Creek.

EXHIBIT 147

Environmental Permits/
Regulatory Review Training

Grady Allen, Bill Horton

ESS Environmental Division

[Training conducted to Fossil/PG mgt. & staff on several ocassions during 1994/1995.]

Avoiding PSD

- No net increases in ton/yr (or ton/hr) emission rate

  – SO2, NOx, PM-10, VOC, CO

  – Fl, Pb, Be, Hg, sulfuric acid mist, HCL, [partially illegible – probable "vinyl"] chloride, chlorinated dioxins, dibenzofurans

- No increased capacity utilization, except for increased power demand

- Representative, actual emissions = 2-yr period w/i 10 yr period following change

* * *

EXHIBIT 148

From: RAM2026 – PRDC Date and time 05/23/97 16:56:42
To: JEE7230 – PRDC
DWS5151 – PRDC
WTH7130 – PRDC
WJM8364 – PRDC Bill McCabe
MJB7220 – PRDC
JJB7235 – PRDC Joe Barna
GDT7206 – PRDC
KWK7265 – PRDC Kris Knudsen

Bobby McMurry, MG03C1, 875-5931
Environmental Engineer
Environmental Engineering, Generation Services
Subject: MSS 3&4 mill replacement and PSD/NSPS mtg 5/20/97

A meeting was held to discuss potential PSD/NSPS issues regarding the MSS3&4 mill replacement. MSS is planning on replacing one mill with a larger mill on Units 3&4 to allow the use of lower quality coal or harder grind coal without derating the unit. When the coal contract was changed in 1995 MSS started receiving some coal that was harder to grind and the existing mills could not feed enough coal to the boiler to meet full load for parts of the year. The purpose of the replacement mills is NOT to increase the maximum generation of the units but to regain load lost due to harder grind coal.

To assure PSD is not an issue a review of 2 representative years of the past 5 years was performed to assure the PSD De Minimus would not be exceeded if the larger mills were available prior to the new coal contract. Using GADS information Units 3&4 was derated due to wet or poor coal 4917 MWhr in 1993 and 920 MWhrs in 1994. If larger mills were available and these derates did not occur an

additional 14 tons of NOx and 33 tons of S02 in 93 and 2 tons of NOx and 5 tons of SO2 in 94 have been emitted which is below the 40 tons/yr PSD De Minimus for each of these pollutants. This demonstrates that the new mills should net trigger PSD.

The next issue is to assure the new mills will not increase. the max hourly generation for NSPS. Marshall historically has been able to achieve approximately 700MWs with the proper coal. The new mills would not allow these units to operate at a greater capacity because of other limiting factors such as feedwater. In other words the new mills would only allow the units to meet unit load with a wider variety of coals.

The mill replacements are scheduled for 1999 and 2000 for units 3. and 4 respectively. Using a 1 year lead time for the equipment, permitting would need to start in early 1998. We would probably need to approach the state in Sept 97 to assure there are no road blocks we are not aware of.

There are some environmental benefits such as some lower sulfur coal is of a harder grind (Belews Coal), lower NOx at a lower loads (BOOS), and potentially lower LOI. We will quantify this but may not use because the mills should be justified independent of the environmental benefits. However, if additional NOx reduction is required (very high likelyhood)additional mill replacements would be required to achieve BOOS at full load which is just part of the Low NOx Burner.

To prep for the September meeting the following action items are needed.

1. Documentation that the mills are not the limiting factor above 700 MWs. Equipment specifications and actual data. Dave Styer

2. Coal information that lower sulfur coal is sometimes harder grind. Bobby McMurry

3. Evaluation of the best option for lower NOx in the .35 to .38 range. Additional mills for BOOS LOFFERS or SOFA without mills. Joe Barna

4. Set up meeting in September with the state. Bill Horton

5. Additional analysis of 93 and 94 MW data to assure representative years.

6. Existing mill specs and replacement mill specs Joe Barna or Dave Styer

If we could get the information by June this would allow us to get it in order prior to September.

Bobby

EXHIBIT 149

* *

MSG FROM: KWK 7265 – PRDC TO: JEP7206 – PRDC 11/02/90 16:29:52
To: JEP7206 – PRDC

From: Kris Knudsen
Fossil Environmental Compliance
Air Quality Group – PROFS KWK7265

Subject: Aux. Boiler Air Requirements

Based on the info you gave me, I've looked further into the permitting requirements for new aux. boilers at Belews.

Info provided: Oil guns: two @ 170 million btu/hr each (Question: Is this one gun per boiler (two total) or two guns per boiler?)

Stacks: 104 feet or less. Present stack: 120 feet.

REGULATORY REVIEW

NSPS
New Source Performance Standards for industrial boilers apply to all boilers with greater than 100 mBtu/hr heat input. NSPS set standards for particulate, SO2, NOx, and monitoring requirements. These are summarized as follows:

Particulate: Emissions must be below 0.10 lb/mBtu, demonstrated by a stack test after initial operation. Subsequent tests not necessarily required, unless the State makes this a permit condition or requests a special test.

Opacity: Must be below 20%, except startup, shutdown, and malfunction. There does not appear to be an exemption

from monitoring, but we MAY be able to argue this based on very low capacity factor.

Sulfur Dioxide: Basically no standard will apply as long as we use a "very low sulfur oil" (less than 0.3 lb/mBtu) or our capacity factor is limited by permit to less than 30%. Number 2 fuel oil would apparently qualify. No monitoring is required if exempt based on the above, but it's possible that we may be required to sample and analyze the fuel oil.

Nitrogen Oxides: Must be below 0.1 lb/mBtu for low heat release burners or 0.2 lb/mBtu for high heat release burners. The transition point is a burner with a heat release of 70,000 Btu/hr-ft3. NOx monitors ARE REQUIRED unless the capacity factor will be below 10%, in which case the operator can submit to the agency a plan to monitor operating conditions to assure that NOx is maintained below the limit. NOx limits should be specified as part of the vendor's requirement, including a plan which we can submit to the state to show how the limit will be met. Apparently this is within the capability of current oil-fired boiler design, but less us know if this a problem.

PSD REQUIREMENTS

PSD review is required for a source which is listed as a "major source" or which has the potential to emit more than 250 tons per year of a pollutant. One "major source" category is a combination of fossil boilers with greater than 250million BTU per hour, so the two boilers would qualify. However, we may be able to show that these are replacement boilers (a "major modification") and that there will be no net increase in emissions, in which case PSD will not apply. This will also depend on the projected use of the new boilers versus the old boilers.

Presuming PSD does apply (we'll try to argue against, but may not succeed), a PSD permit must be issued before beginning construction. This requires 1) ambient air modeling to show protection of air standards and allowable increments for deterioration of air quality; and 2) review of the proposed control technology. Tighter controls could be required, but are not likely for this type of boiler or expected utilization.

More significant is air quality modeling and the time to get a permit. The proposed stack height could very well show problems with modeling especially considering the height of surrounding structures. The model will also have to consider emissions from the two generating units and any other sources in the area. Approval of a modeling plan and time to complete the model could require several months, with a total time to permit taking up to a year. Any problems (i.e. stack height) will also have to be resolved. I will ask Design to look more closely at a rough estimate of whether we could expect problems with the model.

Please advise as to the next step in your process. If you will be proceeding, it will be important to get the permitting people in Design involved as soon as possible since they currently have a number of new facility projects underway. I certainly believe there is nothing in the way to stop this project, but we will require a good bit of lead time.

cc: BKS7265 – PRDC Keith Sipe
DAM7265 – PRDC Dan Markley

Thanks,

Kris Knudsen
373-5104

* *

MSG FROM: TO: 11/06/90 11:26:49
JJB7235 – PRDC JEP7206 – PRDC
To: BOB7235 – PRDC

*** Reply to note of 11/06/90 08:55

Subject: Aux. Boiler
The station has received information from B&W that a drum assessment would require inspection of all longitudinal and girth welds, 5% tube penetration inspection, and inspection of all other penetrations. Due to the welding of tubes to the drum the station would like to increase the tube penetration inspection to 10% or 100 tube connections. The other inspections are felt to be unwarrented due to the temperature and pressure under which the boilers have been operated. This work is rougly scheduled for the end of next week as long as #2 can get on line this weekend.

cc: JEP7206 – PRDC DAN7235 – PRDC

* *

MSG FROM: TO: 11/06/90 14:36:38
BOB7235 – PRDC JEP7206 – PRDC
To: JEP7206 – PRDC

Subject: Aux. Boiler

This is what Joe Barna said about the aux. boiler when I asked about a contact from B&W. The note does not say anything about UT or MT as to what kind of test to do. If you do not find out anything different we will plan to do a MT on the areas defined. What kind of push is this when you get ready for QA. Is it rush enugh for weekend work or if we don't start on thursday would it be better to wait to monday or tuesday of next week so the test can be two

consective days. Sorry for so many questions just trying to get a better handle on what to tell QA.

Thanks
*** Forwarding note from JJB7235 – PRDC 11/06/90 11:26 ***
TO: BOB7235 – PRDC

*** Reply to note of 11/06/90 08:55
Subject: Aux. Boiler
The station has received information from B&W that a drum assessment would require inspection of all longitudinal and girth welds, 5% tube penetration inspection, and inspection of all other penetrations. Due to the welding of tubes to the drum the station would like to increase the tube penetration inspection to 10% or 100 tube connections. The other inspections are felt to be unwarrented due to the temperature and pressure under which the boilers have been operated. This work is rougly scheduled for the end of next week as long as #2 can get on line this weekend.

CC: JEP7206 – PRDC DAN7235 – PRDC

****

MSG FROM: TO: 11/19/90 15:31:32
BOB7235 – PRDC JEP7206 – PRDC
To: JEP7206 – PRDC

*** Reply to note of 11/19/90 15:16
Subject: Aux Boiler Drum Assessment
I will give you a outline of the stress relief, repairs and tube welding when I have figured it out. Can you give me a deadlinedate? I know you are trying to do the work next year. I am trying to get some information from Joe Barna or Bill Turner on the tubes we have been welding at

Riverbendbut I have found out that they are in a different situation

Thanks

* *

MSG FROM: KWK7265 – PRDC TO: JEP7206 – PRDC 11/28/90 14:04:51
To: JEP7206 – PRDC James E. Plybon
ICB7230 – PRDC James C. Burnette

From: Kris Knudsen
Fossil Environmental Compliance
Air Quality Group – PROFS KWK7265

Subject: Aux. Boilers

Any further word on where to proceed with new aux. boilers? Let us know if we can help.

Also, this review brings up the issue of an air quality permit for the existing boilers. We were under the impression that the boilers were less than 100 million Btu/hr heat input, which would exempt them from having a permit. For a boiler over 100mBtu/hr, a permits is required unless the DEM specifically grants a request for exemption. To our knowledge, we have not asked for this exemption. We will investigate further to verify whether there has been any correspondence with the State. Please advise if you are aware of any information.

Because of the size of these boilers, also be aware that any major modification is subject to review for NSPS/PSD applicability. The primary consideration should be whether the work will allow any greater utilization (more emissions), but regulations will also apply if the cost of repairs is more than 50% the cost of a replacement boiler.

cc: AMW7206 – PRDC GDT 7206 – PRDC
BKS7265 – PRDC Keith Sipe

Thanks,

Kris Knudsen
373-5104

* *

MSG FROM: TO: 11/28/90 13:16:26
GTB7230 – PRDC JEP7206 – PRDC
To: JEP7206 – PRDC Jim Plybon

Glenn Burney
Belews Creek – Operations
429-0501
Subject: Auxiliary Boilers
Glenn
*** Forwarding note from EFG7230 – PRDC 11/27/90 15:16 ***
To: GTB7230 – PRDC

FROM: EVERETT GREENSTREET
BCSS
NATION'S BEST

Subject: Auxiliary Boilers
EV
429-0500
*** Forwarding note from HWS7206 – PRDC 11/27/90 15:12 ***
To: EFG7230 – PRDC MWC7290 – PRDC
DEW7220 – PRDC HCJ7260 – PRDC
HMF7250 – PRDC WFH7200 – PRDC
MLB2468 – PRDC RLD7210 – PRDC

From: HWS7206 Howard W. Shea
FOSSIL OPERATIONS WC-1665
Phone 373-2323
Subject: Auxiliary Boilers

FPD GO Environmental is reviewing possible permitting requirements for existing Auxiliary Boilers and have requested the following information:

– Max. Heat Input, million BTU per hour
– Type of fuel
– What are uses of boilers
– Expected utilization, hours per year

I have the following from 3 years ago when we provided some of the information:

STATION	HEAT INPUT< Million BTU per HR	FUEL
BC	2 blrs at 96 each	#2 oil
BK	1 blr at 21	"
CS1-4	1 blr at 6	"
CS5	1 blr at 75	"
DR	1 blr at 15	"
LS	1 blr at 8	"
MS	1 blr at 172	"
RB	1 blr at 2	"
PROPOSED		
LS	3 blrs at 15 each	No 2 oil or gas
AS	1 blr at 33No. 2 oil	
or		
1 blr at 43	No. 2 oil	

Please review the information for accuracy and in Lee's and Allen's cases give me the information on the boilers you installed.

Also for all stations will need the hours per year use and use for the boilers(plant, deaeration of DI make up, unit start, etc).

Please try to provide by Dec. 15, 1990 to H. Shea.

Thanks,

Howard

cc: AMW7206 – PRDC KWK7265 – PRDC

****

MSG FROM: TO: 11/28/90 13:19:16
GTB7230 – PRDC JEP7206 – PRDC
To: JEP7206 – PRDC Jim Plybon

Glenn Burney
Belews Creek – Operations
429-0501
Subject: Aux. Boiler
From the sound of this note I think it is important to figure out as soon as possible what CMD sees as there part in this project. I believe we will be hard pressed to have this project completed by July.
Glenn
*** Forwarding note from OWS7207 –PRDC 11/27/90 16:19 ***
To: GTB7230 – PRDC Glenn T. Burney

FROM: O.W. (Walt) Sealy
WC-1531
Subject: Aux. Boiler
Glenn, I talked with Everett today about the subject project. CMD indicated they would have resources available from Jan. '90 through July '90 to do the project. Everett indicated there was not sufficient damage to the drum to warrent replacement so we would probably repair rather than replace the aux. boilers. In order to get the funds approved, I need and estimate of both materials and installation. Jim Plybon and Joe Barna have been working on this project. CMD will be able to support at other times but the time frame indicated is preferable.

cc: RTB7202 – PRDC

Thanks, Walt
373-7058

* *

MSG FROM: TO: 11/28/90 16:12:12
JEP7206 – PRDC HWS7206 – PRDC
To: HWS7206 – PRDC Howard Shea – Foss

From: Jim Plybon
BELEWS CREEK STEAM STATION
Phone # 429-0507
Subject: Auxiliary Boilers

Howard:

How are things going down there? Good I hope.

The following is information you requested on the BC Aux boilers.

Max heat input is 170 million BTU/Hr per boiler
Fuel is #2 fuel oil
The boilers are used for unit startup.
The expected utilization of these boilers is approx. 62 hours per year.
(This includes test firing once per week and a cold unit startup once every two years.)

EXHIBIT 151

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

Civil Action No. 1:00 CV 1262

UNITED STATES OF AMERICA,

Plaintiff,

ENVIRONMENTAL DEFENSE
NORTH CAROLINA SIERRA CLUB,
NORTH CAROLINA PUBLIC
INTEREST RESEARCH GROUP,

Plaintiff-Intervenors,

vs.

DUKE ENERGY CORPORATION,

Defendant.

_____/

DEPOSITION OF WILLIAM T. HORTON
(Taken by Plaintiff)
Charlotte, North Carolina December 4, 2002

* * *

[104] Q. How many times did you contact the State?

A. I would estimate four or five.

Q. Did you tell the State during any of those contacts about the other work that was being done to the unit during that outage?

A. I did not.

Q. Did you know the specifics of the work that was being done during that outage?

A. I think I was generally aware of the kinds of activities that were being planned, participated in some early meetings as part of a team, did not see those meetings through to conclusion and do recall – do recall – I'm trying to remember. I think I've answered the question though.

* * *

[105] Q. So did you notify the State or put the State on notice on any occasion of the work that was being done at the boilers that we've alleged in our complaint?

MR. SOMERS: Object to the form.

THE WITNESS: I personally did not and where I had general knowledge wouldn't have [106] thought it necessary because they were deemed to be routine maintenance.

BY MS. BEHLES:

Q. So you would have deemed it unnecessary to put the State on notice because you thought that you didn't need a permit, is that a fair statement to make?

A. Routine maintenance does not require a permit.

Q. Okay.

(Thereupon, Plaintiff's Exhibit Number 653 was marked for Identification.)

BY MS. BEHLES:

Q. Okay. Mr. Horton, I've now handed you what's been marked as Exhibit 653, it's a letter from, I believe, you dated February 16, 2001. You want to just take your time to look it over and let me know when you're ready.

A. Okay. I recall this.

Q. Okay. First of all, did you write this letter?

A. I did.

Q. Okay. Who is this letter being written to?

A. It is being written to the regional permitting contact in Winston-Salem office.

* * *

EXHIBIT 152

IN THE UNITED STATES DISTRICT COURT FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

CIVIL ACTION NO. 1:00 CV 1262
UNITED STATES v. DUKE ENERGY CORPORATION

EXPERT TESTIMONY REPORT OF RANAJIT (RON) SAHU

/s/ Ranajit Sahu

ON BEHALF OF THE

UNITED STATES

AUGUST 1, 2002

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G. DETAILED RESULTS OF EMISSIONS CALCULATIONS.....

H. DOCUMENTS CONSIDERED.....

Information Required by Federal Rules of Civil Procedure

The following is a listing of the items provided as required by the federal rules of procedure:

1. This report contains my opinions, conclusions and the reasons therefor; and,

2. Attachment H lists the data or other information I used in forming my opinions; and,

3. A statement of my qualifications is contained in Attachment A; and,

4. A list of publications I have authored within the last ten years is shown in Attachment B; and,

5. My compensation for the preparation of this report and my testimony is included in Attachment C, and,

6. A statement of my previous testimony within the preceding four years as an expert at trial or by deposition is contained in Attachment D.

This report contains calculations and conclusions based on data and information in my possession at the time of submittal of the report. In some cases data requested from Duke Energy Corporation was still pending and had not been received prior to submittal of the report. Should additional data or other documentation become available I reserve the right to appropriately revise my analysis, calculations, and conclusions and to supplement the contents of this report.

I. BACKGROUND AND EXPERIENCE

I. Ranajit Sahu, have over fifteen years of consulting and teaching experience in the fields of mechanical, environmental, and chemical engineering including, design and specification of equipment, air pollutant emissions calculations and analysis (specifically from coal combustion), air pollution control and equipment design, combustion engineering (specifically including coal combustion), process engineering, energy studies, transportation air quality impact analysis, dispersion modeling,

health risk assessments, regulatory strategy developmen and design for pollution prevention. I have over ten yeai of project management experience and have successfull executed over 300 projects in this time period. This ir cludes basic and applied research, design, regulator compliance, permitting, energy, risk, and public interfac projects. I have provided comprehensive multimedi compliance assistance encompassing all media – ai water. solid and hazardous waste, mixed waste, noise, an community issues – to numerous industrial, government and commercial clients during the last decade. My client have included major petroleum refineries, steel plants cement companies, power generation facilities, and th government sector. To date, I have performed projects i over 40 states (including in North and South Carolina · working on Title V and other permitting matters) in th United States, numerous local jurisdictions and interna tionally.

I have a B.S., M.S., and Ph.D., in Mechanical Engi neering, the first from the Indian Institute of Technolog (Kharagpur, India) and the latter two from the Californi Institute of Technology (Caltech) in Pasadena, California My research specialization was in the combustion of coa and, among other things, understanding air pollutio aspects of coal combustion in power plants.

Some of the clients I have assisted on a variety of ai pollution permitting and other regulatory matters in clude San Diego Gas and Electric, Shell Oil Company British Petroleum, Chevron, Mobil, Honeywell, Northrup Grumman, Holnam Cement, Southdown Cement, Oregor Steel Mills, and Birmingham Steel Mills.

In addition to consulting, I am also active in teaching. Over the past 9 years I have taught, and continue to teach, a number of courses (e.g., Introduction to Air Pollution, Atmospheric Chemistry and Physics. Risk Analysis and Management, Process Safety Management, Air Toxics and Risk Analysis, Transportation and Air Quality, etc.) in several Southern California universities including UCLA, UC Riverside, Loyola Marymount University and Cal State Fullerton. In addition, I have also taught air quality and engineering courses at my alma mater Caltech (Heat Transfer) and at the University of Southern California (Air Pollution). I have also provided training in air pollution and energy regulatory issues to Southern California Gas Company and at the Institute of Gas Technology, Chicago.

Additional details regarding my background and experience can be found in my resume provided in Attachment A and in the list of publications and presentations provided in Attachment B. Attachments C and D contain a statement of compensation and my previous expert witness experience, respectively.

II. SUMMARY OF TESTIMONY REPORT

For this proceeding, I have been requested by the United States Department of Justice (DOJ) to provide a report that addresses the following items:

1. the process by which certain air pollutants (specifically, nitrogen oxides (NO_x), sulfur dioxide (SO_2), and

particulate matter (PM[1])) are generated and emitted by utility coal fired power plants;

2. the general methods of estimating and measuring such emissions to the atmosphere;

3. a major regulatory program under the Clean Air Act (and its Amendments) that can apply to certain coal-fired power plants: the New Source Review (NSR)/ Prevention of Significant Deterioration (PSD) program;[2]

4. a description of the status of the PSD program pursuant to the State of North Carolina State Implementation Plan (SIP) and the State of South Carolina SIP and how this would have applied to the various modifications;

5. the methods used in, and results derived from, specific emissions estimates of SO_2, NO_x, and PM from all of the units operated by the Duke Energy Corporation (Duke) in connection with this proceeding. Specifically, I developed estimates of the quantity of pollutants emitted (or anticipated to be emitted) by each generating unit in this proceeding during specific periods both prior and subsequent to each of the component replacement projects

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[1] Although particulate matter (PM) is generated during coal-fired combustion, in the present instance all Units in connection with the current proceeding have electrostatic precipitators (ESP) to control PM emissions. It is anticipated that a significant portion of the PM emitted into the atmosphere (roughly 67%) would be smaller than 10 microns in aerodynamic diameter – i.e., PM_{10} (see AP-42 Table 1.1-6). In this report, since Duke's PM source testing data are used for calculating and developing PM emissions estimates, PM refers to total particulate such as that obtained from EPA Method 5 testing. PM_{10} is later calculated from the PM estimate by using this fraction, i.e., 0.67. In the text PM also refers to PM_{10}.

[2] 40 CFR 51.

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described in the United States' Amended Complaint.[3] These emissions estimates are based on data and information that was available to Duke prior to each such component replacement, as well as other public information from public data sources. The emission estimates are based on approaches that could reasonably have been used by Duke in making judgments regarding the applicability of the federal NSR/PSD program and, as relevant, the applicability of the North Carolina and South Carolina SIPs to the respective component replacement projects;

6. for each component replacement project, the comparisons of the unit's emissions both prior and subsequent to the project, using several different comparison tests. Although the regulations do not require a source to conduct each and every one of the comparisons I have performed in every instance, to determine whether a project will result in an emissions increase as defined by the regulations, I have conducted an array of retrospective comparisons based on data that would have been available to Duke and using methods that also would have been available to Duke to aid the Court's evaluation of regulatory determinations. For those calculations aimed at projecting the effect of the modification on emissions of the unit, I relied on both Duke's own internal estimates of the likely effect of the modification on generation (and consequent emissions), and on information derived from the Generating Availability Data System (GADS)[4] and from other system planning modeling projections[5] regarding

[3] United States of America v. Duke Energy Corporation, Complaint.

[4] Generating Availability Data System. Data Reporting Instructions, October 1999.

[5] This projections used modeling tools such as PROMOD or similar programs. Details pertaining to this are provided in the expert report of Mr. Bruce Biewaid.

unit performance as reported by Duke. GADS loss data directly provide "activity factors" for emissions calculations such as losses in unit generation availability due to specific causes. This data, once appropriately adjusted for unit utilization due to demand and dispatch, can identify causal relationships between outages or deratings and specific component failures or malfunctions. Thus, adjusted GADS generation loss data, converted appropriately to emissions, was used to determine the emissions increases that could have been projected as a result of specific component replacements. As noted above, GADS data was used because it was readily available to Duke at the time of each modification. Similarly, the projections of future unit capacity made by PROMOD or similar programs by Duke prior to each modification directly show the anticipated manner in which particular units were likely to be operated by Duke in the future.

III. HOW EMISSIONS ARE FORMED DURING THE PRODUCTION OF ELECTRICITY FROM COAL

The primary purpose of burning coal[6] in a boiler is to generate heat by reacting the coal with oxygen present in air. The most significant reactive constituents of coal are

[6] In addition to coal, a "coal-fired" power plant boiler can also use small quantities of other fuels such as various fuel oils (such as diesel) or natural gas at startup. Similarly, other supplemental fuels or fuel sources such as used tires may also be used to generate heat in the boiler. In fact, at times, similar materials as well as others have been used at the various Duke units – however, the resulting heat releases from such fuels is generally so small in relation to that from coal that their effects were not directly considered in the overall analysis presented in this testimony. Any adjustments to account for the use of such startup and supplemental fuels are not anticipated to change the conclusions of the analysis.

carbon, hydrogen, nitrogen, and sulfur.[7] Coal also contains ash which does not play a role in heat release, Carbon (C) and hydrogen (H_2) are significant because they are the primary sources of the heat released. Carbon is by far the largest component of coal, often comprising 80% or more of the total mass of many coals.[8] Nitrogen (N_2), sulfur (S), and ash are significant because they are released in various forms as compounds relevant to air pollution. In addition to being present in combustion air, nitrogen may also be contained in the coal itself.[9]

The extent to which these elements are present in the coal burned depends on the source and type of the coal. Coal is mined in many different parts of the United States and is usually classified according to heat content, sulfur content, ash content and moisture content.[10] Other characteristics such as hardness and grindability are of interest for the purpose of fuel preparation considerations.

Heat content is measured in units of British Thermal Units (BTU) per pound of coal. A BTU is the amount of energy required to raise one pound of water one degree Fahrenheit. The heat content, (which is directly related to the carbon and hydrogen contents), as well as the nitrogen, sulfur and ash contents may vary according to the source of the coal burned at a particular power plant. The sulfur, ash, and moisture contents can vary depending on the source of the coal, its ultimate origins and its age.

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[7] Steam – Its Generation and Use. Babcock and Wilcox, 40th Ed., 1992, Ch. 8.

[8] Ibid.

[9] Ibid.

[10] Ibid.

During the combustion/oxidation process, the elements contained in the coal – including C, H_2, N_2, and S – react with O_2 (i.e. oxidize) to form new compounds. Most of the carbon contained in the coal is thus transformed to carbon dioxide (CO_2) along with some amounts of carbon monoxide (CO). The hydrogen is generally transformed to its oxide, namely water vapor (H_2O). Nitrogen and oxygen combine in the boiler to form various oxides of nitrogen including NO, NO_2, and small quantities of N_2O. The first two of these pollutant oxides of nitrogen formed by combustion are often referred to as a class of compounds known as NO_x. NO_x is formed not only by the N_2 in the coal (fuel NO_x), but is also formed by the reaction of the N and O_2 found in the air used for combustion (thermal NO_x). Oxygen reacts with S to form several compounds, including the air pollutants sulfur dioxide (SO_2) and sulfur trioxide (SO_3). The ash in coal is comprised of metals and metal oxides. Many of the metals that exist in the coal in elemental form also react with O_2 to form additional metal oxides. Some of the ash in the coal drops to the bottom of the boiler. This ash is referred to as bottom ash. The remaining ash, referred to as fly ash or particulate matter (PM), is carried out of the boiler along with the other gaseous products of combustion, including those described above. This mixture of combustion products is known as flue gas. Flue gas, therefore, contains CO_2, H_2O (vapor), CO, SO_2, NO_x, various amounts of particulate matter, and numerous other compounds in smaller amounts.

In summary, most of the pollutants that are present in the flue gas are either initially present in the coal matrix (such as ash) or, are chemically formed in a complex series of reactions during the processes of oxidation of various coal constituents with combustion air. The pollutants of

interest in this proceeding are NO_x, SO_2, and PM. The rate of formation and release to the atmosphere of these pollutants is primarily a function of:

(a) the type of coal (depicted by the heat content and the contents of nitrogen, ash, sulfur, and moisture in the coal);

(b) the rate at which the coal is introduced, or fed, into the boiler;

(c) the physical form in which the coal is fed into the boiler;

(d) the types of burners used in the boiler;

(e) the amounts of air used for combustion;

(f) the manner in which the air is introduced; and

(g) the presence of air pollution control devices designed to minimize the formation of, or enhance the destruction or capture of; these pollutants.

Of these various factors, the amount of coal fed per unit of time (usually tracked in units if tons/hour, millions of pounds/month, or thousands of tons/month, etc.) is a significant factor. This parameter directly relates to the size of a unit. Typically, assuming similar design, operation practices and pollution controls, the higher the nitrogen, sulfur and ash contents of the coal, and the higher the coal feed rate, the higher the amount or quantity of the pollutants NO_x, SO_2, and PM that are emitted from power plant boilers into the atmosphere.

Of course the primary purpose of burning coal in a boiler is to liberate the chemical energy contained in it to

generate heat. This heat is then transferred to a working medium (typically water, which upon being heated becomes steam), and, in turn, the steam is used to create mechanical work (or, more accurately mechanical power) in a turbine. Finally this mechanical power is converted to electrical energy (megawatts) in a generator. Thus, for a specified type of coal and boiler design, higher coal feed rates generally imply higher electricity, generation rates. Since higher coal feed rates imply higher emissions of pollutants per the discussion earlier, it follows that, higher electricity generation rates generally result in higher emissions rates of pollutants to the atmosphere.

IV. CAA AND RELEVANT STATE REGULATORY PROGRAMS

The Clean Air Act (CAA), and the regulations promulgated to enforce its provisions have been modified several times over the years since 1970. These modifications have added several air pollution prevention and control provisions designed to protect and enhance the quality of our Nation's air resources. This section will discuss one of the major regulatory programs that forms the cornerstone of the regulatory air pollution prevention and control strategy which strikes a balance between economic growth on the one hand and attainment/maintenance of health-based ambient air quality standards on the other hand. These National Ambient Air Quality Standards (NAAQS) are goals that are supposed to be attained or met throughout the nation. The NAAQS establish health-based levels of certain "criteria air pollutants" applicable to all persons in all areas of the country. The pollutants of interest in the

present proceedings (NO_x, SO_2, and PM) are criteria pollutants.[11]

The major regulatory program that will be discussed below, namely the New Source Review (NSR) program [40 CFR 52], generally takes a predictive, annual, facility-wide view of the impacts of facility emissions for specific listed pollutants on the ambient air. If applicable, the NSR program requires sources to put on the best possible controls[12] that are technically feasible and economic (only BACT requires a consideration of economic factors) and to demonstrate, via mathematical or computer-based modeling, that estimated or projected post-control emissions from plants are not in conflict with ambient air quality goals.

IV.1 NSR/PSD Regulations

The basic requirements of the New Source Review (NSR) program are established in parts C and D of Title I of the Clean Air Act. The purpose of the program is to protect, among other things, public health and welfare, even as new sources are built and existing sources expand to meet economic growth considerations. Specifically, its purpose is to ensure that:

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[11] United States of America v. Duke Energy Corporation, Complaint.

[12] These controls or corresponding emissions levels are either called Best Available Control Technology or BACT (to be applied to sources in areas where the NAAQS are already being attained) or Lowest Achievable Emission Rate or LAER (to be applied to sources in areas where the NAAQS are not presently being attained or non-attainment areas).

(a) air quality does not worsen where the air is currently unhealthy to breathe – i.e., in non-attainment areas; and

(b) air quality is not significantly degraded where the air is currently clean – i.e., where current standards are attained or attainment areas.

The fundamental philosophy underlying NSR since its inception is that a major source should install modem pollution control equipment when it is built (for new sources) or when it makes a major modification that increases emissions significantly (for existing sources). Congress believed incorporating pollution controls into the design and construction when new units are built or when old ones are modified significantly is generally the most efficient way of controlling pollution from major sources.

NSR requires a major source to obtain a permit and undertake other obligations *prior to* construction to control its emissions of air pollution. For new sources or for sources that have not begun normal operation (i.e., such as after a non-routine physical change or a change in the method of operation) NSR applies if the construction project results in the potential to emit[13] air pollution in

[13] The reason for not using the unit's post-modification actual emissions (as opposed to its PTE) in the case of a non-routine change or a change in its method of operation is that the modification or change in the method of operation could change the emissions characteristics of the unit making the pre-change actual emissions unreliable as a predictor of its future emissions for the pollutant in question. For example, emissions of certain pollutants depend on the unit's (or unit plus control system, if one is present) load factor (for example. NO_x emissions from a boiler or PM_{10} emissions from the electrostatic precipitator or ESP) or how close to its maximum design capacity it is run. If the modification or change in the method of operation makes it

(Continued on following page)

excess of certain threshold levels established in the NSR regulations. For a new source, NSR is triggered only if the potential emissions qualify the source as major. For an existing major source making a modification (i.e., the present situation in the case of Duke, where each unit at each plant is a major source), NSR is triggered only if the modification will result in a significant increase in emissions. This increase is calculated using regulatory guidance as will be described later.

In general, the NSR program is administered by state and local air pollution permitting authorities. Each state or local permitting authority is required to incorporate the basic NSR program requirements into its State Implementation Plan (SIP), which is the state's plan to ensure progress toward, or maintenance of, attainment of all National Ambient Air Quality Standards (NAAQS). A state's NSR program may be approved, either by incorporation into a SIP, which is approved by EPA, or by delegation to the state by EPA. If the state designs its own program, EPA may approve it so long as it meets the criteria listed in federal regulations [40 CFR 51]. Otherwise, the state may request delegation of the federal NSR program, as it is written in the federal NSR regulations [40 CFR 51]. For the entire time period under consideration in the present proceedings, the States of North Carolina and South Carolina had a delegation status from EPA for NSR.

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possible that the unit could run at a higher load factor that before modification, using past actual emissions is not useful.

Distinction Between Non-attainment NSR and PSD

The term NSR is used to refer to the Clean Air Act's construction permit program for major sources. However, the major NSR program is actually comprised of two separate programs: Nonattainment NSR and Prevention of Significant Deterioration (PSD). These two programs have separate requirements to address the differing air quality planning needs in the differing areas where they apply. Nonattainment NSR applies in areas where air is unhealthy to breathe – i.e., where the established NAAQS for a criteria pollutant is not being met ("non-attainment" areas). PSD applies to major sources located in areas where air quality is currently acceptable – i.e. where the NAAQS for a criteria pollutant is being met (i.e., "attainment" areas). With the exception footnoted below, the areas, surrounding the various Duke plants were generally in attainment of all relevant NAAQS [40 CFR 52.721] and have been during the time frame relevant to the present proceedings[14]. Thus, except for the Allen and Riverbend plants for certain periods of time relevant to these proceedings, the type of NSR that would apply for the modifications alleged in this case is PSD. Although the nonattainment NSR program would apply for some of the Allen and Riverbend plant modifications, I have conducted this analysis assuming that they are also subject to PSD. The initial emissions-based assessment for both programs is the same.

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[14] It is possible that for certain periods of time relevant to these proceedings the Allen and Riverbend plants, located in Gaston County, North Carolina, were located in an area with a maintenance plan for the criteria pollutant ozone (one of whose precursor pollutants is NO_x).

Determination of Major Sources and Significant Increases

The first step in determining whether new construction or modification is subject to PSD is to define the source and determine its emissions. Next, the source's potential emissions are compared to the appropriate major source threshold defined by law or regulation. Major source thresholds are defined in terms of annual emissions (i.e., tons per year). For PSD (or for nonattainment NSR), the major source threshold is generally 250 tons per year. but, the PSD major source threshold is 100 tons per year if the stationary source belongs to a list of 28 source categories (i.e. industrial groupings) which includes fossil fuel fired steam electric power plants such as each of the Duke plants subject to this litigation [40 CFR 52.21].

A source's potential emissions, (i.e., "potential to emit") is defined[15] as "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted. . . . , shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable." Enforceable permit conditions can limit a source's potential to emit the maximum amount possible under its physical and operational design. A new source under construction (i.e., a "greenfield" source) is subject to NSR if its potential emissions will exceed the major source threshold. Applicability of PSD to greenfield sources is relatively straightforward, because the emissions

[15] 40 CFR 52.21(b)(4)

from the new source are relatively easy to estimate. The other type of change that can trigger PSD is a major modification at an existing major source. The Clean Air Act defines a modification [40 CFR 52.21] as a physical change or change in the method of operation of a major stationary source that results in an increase in emissions, or emissions of a new pollutant. Examples are a new production line, an equipment upgrade, or reconfiguration of a process. Implementing regulations exempt certain activities from the definition of physical or operational change. These include, for example: routine maintenance, repair or replacement of equipment, increases in hours of operation or production rate not involving physical and operational changes (unless the increase is prohibited under an existing permit), or changes in ownership.[16] If there is no physical change or change in method of operation, or if the change falls under one of the exemptions just described, then PSD or nonattainment NSR does not apply to the change, and emissions need not be determined.

A physical change or change in method of operation (i.e., a modification) is subject to PSD if it results in a significant net emissions increase of any regulated pollutant under the Clean Air Act. Just like the definition of a major source, the ND regulations establish levels that define major modifications, known as significance levels, which vary by pollutant.[17] The provision allows for *net* emissions increases if the source can offer past or concurrent emissions reductions at its other units to

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[16] New Source Review Workshop Manual, Draft, October 1990, Section III.A.

[17] New Source Review Workshop Manual, Draft, October 1990, Table A-4.

counterbalance the increase from the proposed change at a given unit.[18] The net emissions increase resulting from the netting calculation must result in an increase above the significance level for PSD to apply.

For modifications at existing sources, the net *increase* in emissions is compared against the significance level, not the entire emissions for the modified unit(s). In some cases it may be possible to directly estimate the proposed net increase. In other instances, this net increase may need to be calculated as a difference between future estimated or projected emissions and current (or baseline) emissions. If the latter approach is used, both the current or baseline emissions must be known or estimated and the future projected emissions must be determined as well. Current emissions are measured using actual emissions over the recent past, usually designated as the two years preceding the contemplated project.[19] Future increases are generally determined using actual emissions. However, for sources that have not begun normal operations (i.e., those sources that have made non-routine physical changes) there is no ready method to determine their future actual emissions. Instead, the implementing regulations require that, in these situations, the source's potential to emit (which, as described above, is the maximum capacity to emit, except as limited by a permit) be used for estimating post-modification emissions. This calculation is often referred to as the "actual to potential" test. The difference between the future potential and the past actual emissions is compared to the relevant significance level. An exception is

[18] A New Source Review Workshop Manual, Draft, October 1990. Section III.B.

[19] 45 FR 52676, 52705, 52718 (1980).

the electric utility industry, which, for modifications after July 1992,[20] is permitted to estimate future emissions using a special calculation that resulted from a federal rulemaking following a federal court opinion. The utility calculation is established in a rule, commonly known as the "WEPCO rule," which EPA finalized on July 21, 1992.[21] This rule provides that utilities can, upon fulfillment of certain conditions[22] compare past actual emissions to projected future actual emissions. This calculation is often referred to as the "actual to future-actual" test.[23]

Basic PSD Requirements

New major sources and existing sources that undertake major modifications that are subject to PSD must apply best available control technology (BACT). When preparing a BACT analysis, the permit applicant must typically undertake the following steps: (1) identify available pollution control options; (2) eliminate the technically infeasible options; (3) rank the remaining control technologies by control effectiveness; (4) evaluate the most effective controls (considering energy, environmental, and

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[20] Final WEPCO Rule, 57 FR 32314 (July 21, 1992).

[21] Final WEPCO Rule, Section B, July 21, 1992.

[22] EPA, in finalizing the WEPCO Rule in 1992, stated (Section B) that " . . . any utility which utilizes the "representative actual annual emissions" methodology to determine that it is not subject to NSR must submit for 5 years after the change sufficient records to determine if the change results in an increase in representative actual annual emissions." Further, EPA also stated that " . . . change does not increase the unit's emissions factor . . . the utility may submit annual utilization data, rather than emissions data, as a method of tracking post-change emissions."

[23] Final WEPCO Rule, Section B, July 21, 1992.

economic impacts) and document the results; and (5) discuss the appropriate BACT selection with the permitting authority. The permitting authority then specifies an emission limit for the source that represents BACT.

For non-attainment NSR, the corresponding controls are called LAER. In determining LAER, only technological feasibility is considered. Cost-effectiveness is not a consideration. Each PSD applicant must also perform an air quality analysis, which may include pre-application monitoring data, to demonstrate that the new emission increase will not cause or contribute to a violation of any applicable NAAQS or result in a significant deterioration of the air quality. Finally, each applicant must also conduct an analysis to ensure that the increase does not result in adverse impact on air quality related values, including visibility, that affect designated Class I areas, such as wilderness areas and national parks.

Changes that do not trigger NSR/PSD

There are a number of ways that sources can undertake new construction or modification without the need for a major NSR permit. First, as noted above, there are certain activities that are exempt from NSR because they are defined in the regulations as exclusions from the definition of a physical change or change in the method of operation. For example, a change which is a "routine repair or replacement" is exempt from NSR. Certain pollution control projects are also exempt from NSR, even those that increase emissions, if they meet environmental safeguards established by EPA.

Even if a change does not qualify for one of these exemptions, a change at a major source does not trigger NSR if

the emissions increase is below the level defined as significant. Many projects have emissions increases that are below these levels and never trigger NSR. Where a project's maximum capacity to emit would be above the significance levels, a source often uses a common NSR avoidance strategy – a limit on potential to emit, or PTE limit. In a PTE limit, a source agrees to limit the size of the proposed project's emissions increase by taking a permit limit to keep emissions below the significance level. Such limitations can be accomplished by installing modern pollution controls (i.e., by reducing its emission factor), or by limiting some aspect of the unit's operation such as by limiting fuel burned or hours operated (i.e., by reducing its activity factor). Furthermore, even if the proposed change would result in a significant increase and cannot be limited as just described, the source may offer creditable contemporaneous emissions decreases at other units to offset the increase from the proposed change. In such cases, the *net* emissions increase attributable to the project may not exceed the significance level.

IV.2 North Carolina SIP Requirements

The CAA [Section 110 of the Act, 42 U.S.C. § 7410] requires each state to adopt and submit to EPA for approval a State Implementation Plan (SIP) that provides for the maintenance, implementation and enforcement of the NAAQS. Per the CAA, each SIP must include a permit program to regulate the modification and construction of any stationary source of air pollution, including stationary sources in attainment and non-attainment areas of the state, as necessary to assure that NAAQS are achieved. Pursuant to Section 113(a) and (b) of the CAA, upon EPA

approval, SIP requirements are federally enforceable under Section 113 [40 C.F.R. § 52.23].

As noted in the Complaint in this case, pursuant to Part C of the Clean Air Act, North Carolina SIP requires that a permit be obtained before construction or operation of a major modification to a major stationary source in an area designated as attainment. This permit should be obtained under 40 CFR s 52.21(i), and North Carolina Administrative Code at Title 15A. Chapter 2, Subchapter 2D, Section .0530 (15A NCAC 2D.0530), which was effective on June 1, 1981, and approved by EPA as part of the federally-enforceable North Carolina SIP on February 23, 1982, at 47 FR 7836, and amended on June 18, 1990, at 55 FR 23735, and on February 1, 1996 (61 FR 3584).

The North Carolina SIP also requires that no construction, modification or operation of any facility which may result in air pollution shall occur without first obtaining a permit under North Carolina Administrative Code at Title 15A, Chapter 2, Subchapter 2Q, Section .0300 et seq. (15A NCAC 2Q.0300 et seq.). This rule was approved as part of the North Carolina SIP on May 31, 1972 at 37 FR 10892, and amended on February 1, 1996, at 61 FR 3584.

The status of the WEPCO provisions adopted after July 21, 1992 by EPA into the Federal PSD regulations in the North Carolina SIP requires a detailed analysis. On March 23, 1995 the state applied to include WEPCO provisions into the SIP and these were approved by EPA on October 4, 1995 (60 FR 51923) with an effective date of December 4, 1995. However, on February 1, 1996 (61 FR 3584) EPA approved a SIP modification submitted by North Carolina on August 14, 1994 with an effective date of April 1, 1996. This February 1, 1996 version of the SIP

did not the contain the WEPCO provisions. Thus, WEPCO provisions ceased to be in the North Carolina SIP on and after April 1, 1996. Subsequently, the state applied for inclusions of the WEPCO provisions into its SIP on March 19, 1997 and these were approved by EPA on October 15, 1999 (64 FR 55831) with an effective date of December 14, 1999. Thus, after December 14, 1999, WEPCO provisions were again included in the North Carolina SIP.

To summarize, the North Carolina SIP did not contain the WEPCO provisions: (a) before December 4, 1995 and (b) during the period starting on April 1, 1996 and ending on December 13, 1999. The SIP did contain the WEPCO provisions: (c) during the period starting on December 4, 1995 and ending on March 31, 1996; and (d) after December 14, 1999 through the present.

IV.3 South Carolina SIP Requirements

As stated in the Complaint in this case, pursuant to Part C of the Clear Air Act, the South Carolina SIP requires that no construction or operation of a major modification to a major stationary source occur in an area designated as attainment without first obtaining a permit under 40 CFR 52.21(i), and South Carolina Regulation 62.5, Standard No. 7, which is part of the South Carolina SIP that was approved by EPA on February 10, 1982, at 47 FR 6017, and amended on October 3, 1989 (54 FR 40662) and most recently amended on August 20, 1997 (62 FR 44219).

Furthermore, the South Carolina SIP, DHEC Reg. 62.5 No. 7, s. III.A requires a construction permit for all major modifications. The South Carolina SIP, DHEC Reg. 62.5 No. 7, s. IV.A, requires that a major plant or major modification apply the best available control technology to each

pollutant subject to regulation under the Act that the major plant emits in significant amounts.

Also, the South Carolina SIP requires that no construction, modification or operation of any facility which may result in air pollution shall occur without first obtaining a permit under South Carolina Regulation 62.1, Section II, which is part of the South Carolina SIP that was approved by EPA on May 31, 1972, at 37 FR 10892, and amended on February 4, 1992, at 57 FR 4158.

The WEPCO Rule has not been adopted by the South Carolina in an EPA-approved SIP as of this writing. However, since the modification at the only South Carolina unit in the case (Lee Unit 3) occurred in 1989/1990, prior to the adoption of even the Federal WEPCO provisions, the point is moot.

V. ESTIMATING EMISSIONS AT POWER PLANTS

The entire regulatory structure relating to the control of air pollutants is predicated upon the ability to quantify the emissions of pollutants into the atmosphere from the source or activity in question. Without this ability, the very foundation of a regulatory approach could not exist. There are numerous reasons as to why emissions estimates may be necessary, including: ability to understand the impacts of such emissions from a source on the surrounding and distant environment; the ability to demonstrate compliance with specific regulatory requirements, such as permit restrictions and the payment of fees; and the ability of anticipate potential future impacts even before they occur. Thus, emissions estimates may be used to reconstruct historical emissions, assess current emissions, and ever

predict future emissions from a given source such as a power plant boiler.

There are numerous methods that can be used to assist in developing such emissions estimates. These are discussed in some detail below. It should be noted that not all of the methods discussed can be used in all cases (i.e., some methods are better suited for the reconstruction of historic emissions while others may be better suited for making future predictions, etc.).

V.1 Direct and Indirect Measurements

If the release of the pollutants NO_x, SO_2, and PM from a power plant boiler smoke stack into the atmosphere is occurring at the time the emissions estimate is being prepared, it may be feasible to directly or indirectly measure and estimate the rate of release of these pollutants and the total quantity of each pollutant emitted in a given time period. Where continuous real-time measurement is not possible, or where a prediction of future emissions is necessary, emissions can be indirectly estimated using source specific information, information about the source category's emission rates at periodic intervals obtained from limited "source tests", and mathematical estimation techniques.

Two measurement methods that have been successfully used to quantify the rate of release, or emission rate, of NO_x, SO_2, and PM from power plant boiler smoke stacks are source testing and continuous emission monitoring systems (CEMS). Each of these methods provides an actual quantity (i.e., mass) of emissions being released for the period of the time for which the information is collected. Unfortunately, to quantify emission before and

after the specific modifications alleged by EPA at the various Duke units, neither of these data sources is available to be used on a consistent basis for each pollutant of interest for all alleged modifications.

Source testing involves the extraction of a sample of flue gas, binding it in a chemical solution, or in water, and transporting the sample to a laboratory for chemical analysis. The typical sampling period for source tests is several hours. The operating conditions for these tests are typically prescribed by the emission limit regulation, and often stipulate that the tests be conducted at "representative," "typical," "maximum," "design," or some other specified operating rate (i.e., exceeding 90% of maximum operating capacity, etc.). Source tests, done pursuant to standard protocols, can provide an accurate representation of the mass of emissions for the specific pollutant if interest emitted during the sampling period. This data, coupled with other process or activity data (such as the amount of coal burned during the same period as the source test or the electricity generated during the same period as the source test, etc.), can be used to generate emission factors (i.e., mass of emissions of the specific pollutant per unit of activity such as coal burned or electricity generated) for the unit where the test was conducted. These emission factors can then be used to estimate mass emissions of pollutants using only process or activity data for other time periods when the unit is operating at the same or "similar" conditions (i.e., similar fuels, similar generating rate, etc.) as during the source test. Source tests are typically conducted at an individual power plant unit no more than once per year, and depending on state or Federal regulation requirements, only once in the life of a power plant unit for initial emission limit compliance

demonstration. Source tests, however, may not always offer a reliable means for quantifying power plant emission rates over extended periods of time, due the short term nature of the test procedures, and the variability of actual operating conditions relative to the test's operating conditions, especially if the unit generation rate varies considerably over time, or if the fuel mix changes.

In this case, Duke provided various source tests at each of the units, some covering the period of interest for PM only. No source test data were available for SO_2 and only few source tests were available for NO_x as of the time this report was written. Thus, given the general lack of source test data, use of actual unit specific source tests for estimating emissions for all pollutants was not practical in all cases.

CEMS are essentially automated source tests. CEMS extract a sample of stack gas, and transport it directly to an on-site analyzer for immediate sample analysis. These are known as extractive CEMS. Some CEMS actually conduct the analysis within the stack, and are known as in-situ CEMS. CEMS, for certain pollutants, are currently required for all power plant boilers that are subject to certain Federal emission standards. For example, all the Duke units subject to the current proceeding are required to have SO_2, and NO_x CEMS under the Acid Rain regulations of Title IV of the Clean Air Act.

The Acid Rain regulation has required continuous measurement, and reporting of hourly emission rates of NO_x, and SO_2 beginning January 1, 1995. The CEMS and measurement data from facilities subject to the Acid Rain regulation are subject to rigorous quality assurance and quality control (QA/QC). As a result of the QA/QC procedures, the

CEMS measurement data are considered a reliable indication of emission rates. The electric utilities operating the CEMS have a vested interest in maintaining the accuracy of the equipment because one means of complying with the Acid Rain SO_2 emission limits is to trade emission credits. A facility that is able to operate a level resulting in annual emissions below their annual limit is allowed to trade, or sell, the resulting emission credits to another facility that has or expects to exceed their limit. The second facility can deduct the emission credits from their actual emissions as a means of attaining compliance with annual emission limits. Because the rigorously vetted Acid Rain CEMS data are only available from the beginning of 1995, I have used acid rain data, where available, to support my emissions calculations in the post-1995 period[24].

Thus, where possible (i.e., available as of this writing) and appropriate, stack tests or CEM data were used. In other cases, AP-42 was used.

V.2 Various Estimating Techniques

For the purpose of determining historical and/or future emission rates, such as in the case of PSD for new or modified sources, actual emissions such as CEMS and stack tests are not usually available for determining emission rates for the multi-year temporal frame of reference needed for analysis. Instead, emissions must be

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[24] Comparing acid rain data for sulfur dioxide with other estimating techniques such as the AP-42 method discussed later, I found general agreement among the methods and I therefore used AP-42 methods to calculate sulfur dioxide emissions in all cases. However, for NOx, I used acid rain data where available and as appropriate for post-1995 emissions estimates.

estimated mathematically using the direct relationship between various activity factors and parameters such as coal consumption, coal constituents, boiler and burner type and the knowledge of formation and behavior of NO_x, SO_x, and PM emissions. The emission estimating techniques available for analysis include:

Material Balance (also known as Mass Balance);

Emission Factor/Activity Factor technique using site-specific emission factors;

Emission Factor/Activity Factor technique using AP-42 Emission Factors.[25]

The material balance approach, which depends on various limiting assumptions, is a standard method used in process engineering analysis based on the concept of conservation of mass, meaning that whatever goes into the boiler must come out at the other end in one form or another. The emission factor/activity factor techniques (hereafter called emission factor techniques for simplicity) using site-specific, or source test-derived emission factors, and AP-42 emission factors are other approaches that do not rely on the restrictive assumptions inherent in the mass balance approach. In both of the latter cases, however, an emission factor that relates the activity of the production to emissions is used to estimate emissions. Each of these three methods are described below, along with a discussion of the efficacy of each method for this analysis.

[25] Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume 1, US EPA.

V.2.1 Material Balance

Material balance emission estimates are an accounting of all material entering and leaving a device (in this case the boiler) that constitutes the source of emissions. In order to use material balance appropriately, the source should generally be operating in a steady-state or time-invariant mode. Further, this approach can only be used for compounds whose chemicals reactions of formation and destruction are well understood. In the absence of these assumptions, the mass flow rates of each input stream to and output stream from the boiler, and the concentration or percentage of the pollutant and pollutant-forming constituents (also called precursors) within each stream must be quantified. For power plant boilers, the ash and sulfur contents of the coal, and the coal feed rates are examples of input precursors and streams, respectively. An algorithm, or mathematical formula, that models the pollutant formation process is then used to define the pollutant generation in the output stream (the exhaust or flue gases). The quality of the material balance estimate depends on the accuracy of the algorithm used to predict the rate of pollutant formation and the accuracy of the input data. Material balance estimates for NO_x emissions are not reliable because the NO_x formation process is very difficult to model. Estimates of SO_2 using a mass balance are more reliable, because the chemical reaction equation for the oxidation of sulfur to SO_2 (neglecting the minor amounts of SO_3 that can also form) can be used as the pollutant formation algorithm.

To accurately use the mass balance approach for a boiler, it is important to identify all output pathways or streams, and the quantity of pollutant (and/or materials that form pollutants) that leave the boiler via each stream.

For example, a small amount of the sulfur entering the boiler in the fuel, adheres to the ash, and leaves the boiler with the ash, rather than as SO_2. This phenomenon is known as sulfur retention. In order to account for sulfur retention in the emission estimate, a retention factor is typically applied. The sulfur retention factors for coal-fired power plant boilers ranges from 4-15% of the total sulfur entering the boiler. The apportionment of the ash entering the boiler in the coal must also be accounted using a similar ash retention factor. Ash retention factors for utility boilers range from 15-50%. Another complicating issue for estimation of PM emissions using a material balance technique is that some of metals, such as mercury, or metal oxides present in the coal do not leave the boiler as solid matter or fly ash, but evaporate and leave in gaseous form that can condense to form particulates. A strict material balance applied to the PM emission rate estimation must include a factor for this secondary pathway of particulate formation.

V.2.2 Emission Factors and Activity Factors

An emission factor is a representative value that relates the quantity or mass of a pollutant released to the atmosphere with an "activity" of the facility associated with the release of the pollutant. The rate of the "activity" of the facility as a function of time is called the activity factor. Emission factors are expressed as the mass of the pollutant released divided by a quantity related to the activity associated with the pollutant release. For example, assume that a factory producing bicycle frames (the "activity") conducted a study that measured plant boiler SO_2 emissions and frame production rates for a specified period. From this study it was determined that one tenth

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of a pound of SO_2 is emitted from the coal-fired factory boiler for each frame produced. In this example, an emission factor of 0.1 lb SO_2 per bicycle frame produced can be developed. This emission factor can be expressed as 0.1 lb/frame. Thereafter, presuming that this emission factor was developed under representative conditions, in order to estimate the annual SO_2 emission rate, one would simply multiply the number of frames produced in a year (called the activity factor) by the emission factor. If 100,000 frames were produced that year, 10,000 lb, or five tons of SO_2 would estimated to have been emitted during that same one-year period. If 200,000 frames were produced, then 20,000 tons of SO_2 would be the estimated emissions.

This emission factor method assumes that the relationship between the activity and the emissions is reasonably constant. Thus, this approach would be valid if the boiler in the example only supported frame production, and did not provide energy to other needs such as heating administrative buildings that place variable energy demand. In the example described above, it was assumed that all boiler activity was directly associated with activity of frame production. If the boiler also supplied energy to other processes at varying levels, the relationship between SO_2 emission rate and frame production would also vary, and the emission factor discussed previously would not apply to those variable conditions that did not exist during the study.

Another important concern is that the SO_2 emission factor developed in the example above can be used to reliably estimate SO_2 emissions only if the sulfur content of the coal remained constant, and if the amount of coal used to produce each frame remained constant. If the coal

supplier was changed after the emission factor study, and the sulfur content increased, then the amount of SO_2 emitted for each pound of coal burned would also increase. This is because the amount of sulfur entering the boiler with each pound of coal had increased so that, although the amount of coal burned may not have increased, that amount of sulfur entering the boiler has increased. Similarly, if the boiler could not produce the energy needed for frame production at the same thermal efficiency, due to malfunction or deterioration of some boiler component, then more coal would have to be burned to produce the energy necessary to manufacture each frame. Again, the rate of sulfur entering the boiler would increase – this time because of the coal feed rate increase – and an increase in the SO_2 emission rate would result, although the number of frames produced would be the same.

Air pollution control devices (APCD) are often used to remove pollutants from the flue gas before exiting the stack and entering the atmosphere. Power plant emissions of NO_x, SO_2, and PM can be controlled using a variety of technologies to treat the flue gas. The capacity of APCD to remove pollutants is often expressed as removal efficiency. The removal efficiency is the percent of the total mass of the pollutant in the flue gas entering the device that is removed from the flue gas before leaving the device. Emission factors often include a component to account for the APCD removal efficiency.

V.2.3 Emission Factor/Activity Factor technique using site-specific emission factors

Emission estimates are sometimes developed using emission factors derived from one or more source tests as discussed earlier, used in conjunction with activity data for

a different time frame. As stated previously, source test sampling periods last for only a few hours and are typically conducted at a high operating rate relative to maximum capacity. Thus, the source test data are very accurate for the test time period, but are only accurate for other periods of operation if the same or reasonably similar operating conditions are present. It is important to realize that for PSD analysis, the time frame used is typically several years and emissions are evaluated in terms of tons/year. Therefore, if operating conditions vary greatly over the time period of the PSD analysis, using an emissions factor based on one or very few source specific stack tests may not be the most accurate estimate of emissions. This is usually the case with a utility boiler such as the Duke boilers that are the subject of this proceeding. The mass emission rates, in terms of tons/year, of NO_x, SO_2, and PM from power plant boilers are affected by many factors, including boiler efficiency, fuel feed rate, as well as the sulfur and ash content of the fuel. Each of these factors can vary all the time, although some vary more than others. Since representative source test data are not available for all of the time periods of interest for all pollutants of interest for the Duke modifications, site specific emission factors could not be developed for NO_x and SO_2.

V.2.4 Emission Factor/Activity Factor technique using AP-42 Emission Factors

To support air quality planning by state and local agencies and to allow sources to estimate emissions, the EPA has developed and maintained an emissions estimation database consisting of specific emission factors by source category. EPA has derived or collected these

emission factors by collecting emissions data from sources in that category and coming up with composite factors that represent normal average operations for that particular source type. These emission factors are primarily used to estimate emissions over long time frames (i.e., years) for individual sources, and groups of sources for air quality planning and permitting purposes. EPA's AP-42 emission factors are well regarded as reliable emission factors to estimate emissions of certain source types and are used by EPA, state air quality agencies, industry trade associations and research institutes, and individual facilities to estimate emissions for a variety of applications. EPA and state air quality agencies have applied the AP-42 technique for estimating the impact of air pollution control strategies on local, regional, and national air quality. Individual facilities sometimes use AP-42 emission factors to estimate annual emissions for permit applications, and annual emission statements. Duke has often used AP-42 emission factors in regulatory submissions and internal analysis.

The AP-42 emission factors are generally developed to represent long-term average emissions. This methodology, applied to power plant boilers, is documented in the "Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, Chapter 1.1, Bituminous and Subbituminous Coal Combustion," portions of which are set forth in Attachment E. The emission factors for electric utility power plant boilers that burn coal were developed using source test emission rates, fuel feed rate, fuel sulfur and ash content, electricity generation rate, and air pollution control equipment removal efficiency from numerous power plants. These factors are intended to represent

actual emission rates during a range of operating conditions. The source testing conducted for AP-42 emission factor development is typically conducted at normal operating conditions.

For coal-fired power plants, EPA has developed a number of different AP-42 emission factors that are very reliable in estimating emission at these sources. These emission factors are specific to: (1) the vintage or age of the boiler (i.e. pre- or post-NSPS Da): (2) the boiler design (e.g. cyclone-fired versus tangential fired) and (3) the different coal types being burned in the boiler (e.g. lignite versus sub-bituminous). In other words, there are specific AP-42 emission factors for different boiler types, depending on the boiler's age, the boiler design, and the type of coal the boiler burns.

First, the age, or vintage of boilers is considered in the classification of AP-42 emission factors for electric utility power plant boilers. Different emission factors are available for boilers not subject to the NSPS of 40 CFR part 60, and for boilers subject to NSPS.

Second, the boiler design is considered in the classification of AP-42 emission factors for utility boilers. The characteristic of the boiler most relevant to its emissions is the burner configuration. The three general configurations are wall firing, tangential firing, and cyclone furnaces. Wall-fired boilers can be either single wall-fired, with burners on one wall firing horizontally into the furnace, or opposed wall-fired, with burners mounted on two opposing walls. For purposes of selection of an appropriate AP-42 emission factor, the boilers in Duke's Belews Creek plant are most accurately considered to fall into this category. The burners of tangential- (or corner-) fired boilers are

mounted in the corners of the furnace area. Except for the Belews Creek plant, the rest of the boilers at all of the other Duke units are tangentially fired. Thus, different AP-42 emission factors are available for wall-fired or tangential-fired boilers.

Third, AP-42 emission factors are classified by the type of coal burned by the boiler. Coal is classified into several categories, including lignite, sub-bituminous, bituminous, and anthracite. The major distinguishing characteristic between the coal categories is the carbon content, volatile matter content, and moisture content. Bituminous coal was combusted at the Duke units under consideration during the relevant time frames and so only bituminous coal emission factors are relevant to this proceeding.

The emission factors contained in AP-42 are rated to provide an indication of appropriateness for estimating average emissions for source activities. The emission factor rating scale ranges from "A" – excellent, to "E" – poor. An "A" rating indicates that the factor has been developed from source test data derived from tests conducted with a sound methodology, from data reported in enough detail for adequate validation, and from data that were chosen at random from many tests conducted at a sufficiently sized population of facilities. A "D" rating indicates that the factor is developed from moderate quality test data from a small number of facilities that may not represent a random sample, and there may be evidence of variability of the emissions measured within the source population. The data quality of AP-42 emission factors used in the present analysis is "A"

V.2.4.1 Applying the AP-42 Emission Factors

Once the appropriate AP-42 emission factor for a utility boiler has been determined, emissions from that boiler are estimated using the AP-42 emission factor, the coal feed rate (the typical activity factor), the sulfur content of the coal (for sulfur dioxide), and the ash content (for PM). For estimating NO_x emission rates, the NO_x emission factor is multiplied by the coal feed rate (in tons/unit of time) to calculate a NO_x emission rate in units of tons NO_x/unit of time. To calculate SO_2 emission rates, the SO_2 emission factor is multiplied by the coal feed rate, a numerical multiplier, and the coal sulfur content (in percent of weight of coal). If this methodology is used, PM emission rates are calculated by multiplying by the coal feed rate, and the coal ash content (in percent by weight of coal).

It should be noted that some additional calculations may be necessary to generate the proper activity factors. For example, since, the AP-42 emission factors are denoted in terms of mass of pollutant per mass of coal used or burned, the most convenient activity factor is the mass of coal used or burned over the time period of interest. In some cases, this activity factor is directly available if the coal use amounts have been recorded. In other cases, however, this rate can be calculated or estimated from other activity factors (such as the amount of gross electricity generated or lost due to malfunction of a specific component, or MWHrs) if the relationship between the various activity factors is known or can be estimated. In the present proceeding, the amount of coal necessary to generate a gross MWHr of electricity at a specific Duke unit can be calculated from actual historical coal usage and electricity production data. Thus, from a knowledge of

electricity generation rates or MWHrs over the time period of interest (whether they be future rates, or projected generation rates due to specific modifications, or lost generation rates attributable to the malfunction of specific components) one can estimate coal use activity factors which can then be used to estimate emissions using appropriate emission factors.

VI. EMISSIONS ESTIMATING METHODOLOGY FOR THIS CASE

Several factors, which are discussed below, were considered in making the decision about which methodology to use to estimate emissions for the PSD analysis described below.[26] The primary criteria used to select the emission estimation methodology and data sources include:

- data availability, for the time frames of interest;
- capacity to characterize emissions of NO_x, SO_2, and PM for conditions representative of operation relevant to the estimation (i.e., actual, potential, projected operations);
- accuracy and reliability;
- ability to reproduce results.

A discussion of each consideration follows, addressing how each method conforms with the criteria used to select the emission estimating technique. The result of this

[26] Separate calculations in connection with the North Carolina and South Carolina SIPs were not performed since the PSD calculations also support the alleged SIP violations at issue here.

analysis is that, except for use of acid rain data for NO_x in the past-1995 time frame and the use of PM source-test based factors[27]. AP-42 emission factors in conjunction with direct activity factors such as coal usage and sulfur content, or indirect activity factors such as gross electricity generation rates or GADS generation loss data was deemed to be a reliable and accurate method of determining emissions at the various Duke plants for PSD analysis.

First, any emission estimation method must be able to rely on available data for the time frame needed for the analysis. Emissions estimation methods used for PSD analysis must be capable of identifying the two-year annual average actual, or "baseline" emissions for the period that precedes the modification[28] subject to the PSD analysis. In some cases, the baseline may involve two-year annual avenge emissions for longer time frames preceding the modification. Where Duke had made source test data available (e.g., PM or, effectively acid rain NO_x data for the post-1995 time period) these data were used. In other cases, the techniques that could be used for the time periods needed were either material balance techniques or the emission factor techniques using source test-based emission factors or AP-42 emission factors and the available activity factors such as Duke fuel and electricity generation or loss data.

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[27] In the hierarchy of emissions estimation methodologies, using source specific emissions data is preferable to other methods, including AP-42 emissions factors. This is especially true when the AP-42 data quality rating is not high. Thus, in this case, the numerous PM source tests were used in lieu of other methods.

[28] This annual period is typically not coincident with a calendar year – thus, the data must support the calculation of any "rolling" 12-month average emissions.

The second criterion used to select the emission estimation technique was the capacity to characterize emissions of NO_x, SO_2, and PM for conditions representative of actual, potential, and projected operations. As stated earlier, when extensive source test data were available they were used. However, this was not possible for all cases. Similarly, the mass balance technique does not fairly characterize emissions of SO_2 for conditions representative of all operations (especially future projected and potential) and certainly does not apply very well to NO_x emissions because the underlying NO_x algorithm is not readily identifiable in specific situations. However, the emission factor technique using AP-42 emission factors and using activity factors such as Duke's operating and fuel data and/or electricity generation data can best provide estimates of emissions of NO_x and SO_2 for all necessary conditions.

The third criterion for deciding on a methodology for accurately predicting emissions was the accuracy and reliability of the method to determine emissions with minimal error for the different units. The accuracy of a measurement or estimation method can only be determined relative to a method of known accuracy. In the case of emissions measurement and estimation when source test data are not used, only EPA source test Reference Methods found in 40 CFR 60, Appendix A, or CEMS conforming to 40 CFR 75 requirements produce emission measurement data of known accuracy. For this proceeding, the emission factor technique using AP-42 emissions factors was selected as the method that produced the most accurate results for the time frame of interest with the data and information available.

The final criterion for selection of the emission estimation method was the reproducibility of results. The calculation technique using activity factors and emission factors (such as the AP-42 emissions factors), and the activity factor data provided to EPA and others such as NERC by Duke are well documented and generally available. The "*Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume 1: Stationary Point and Area Sources, Section 1.1, Bituminous and Sub-bituminous Coal Combustion*" is available on the EPA Internet web site. The Duke generation and fuel data are publicly available from the company itself. Duke also had the necessary generation loss data attributable to specific component failures and had provided such data to NERC. The emission factor technique using AP-42 emissions factors is simple, straightforward, and does not require assumptions that would lead to non-reproducible results.

For all these reasons, the emissions factors technique using AP-42 emission factors and using Duke fuel use and/or generation data, was selected as the best technique for estimating emissions of NO_x and SO_2, for the various Duke units. For post-1995 NO_x calculations, acid rain data was used. For PM source test data were used.

The specific AP-42 emission factors used for the analysis for SO_2 (all units) and NO_x (all tangential fired units) are shown in Attachment G[29]. These are the

[29] It should be noted that although AP-42 emission factors (with data quality rating "A") were used for all units. I compared SO_2 acid rain data (after 1995) to the SO_2 AP-42 emission factor and found that there was close agreement between these methods. Therefore, although I could have used SO_2, acid rain data for posi-1995 modifications. I continued to use the AP-42 emission factor approach for SO_2 in all cases.

emission factors for boilers firing pulverized bituminous coal with tangential fired boilers and were obtained from the "*Compilation of Air Pollutant Emission Factors AP-42. Fifth Edition, Volume 1: Stationary Point and Area Sources, Section 1.1, Bituminous and Subbituminous Coal Combustions,*" portions of which are provided in Attachment E. NO_x emissions for the cell-fired Belews Creek units were estimated using acid rain data. The emission factors in Attachment G used in the NSR evaluation emission calculations each have an "A" quality rating.

V1.1 PSD Calculations

VI.1.1 "Unit" Emissions Calculations

In order to support the emissions calculation comparisons for the PSD applicability portion of the current proceedings discussed later in this section, several types of "unit" or basic calculations were performed.[30] Each of these "unit" or basic calculations can then be used, in a variety of combinations, to analyze the effect of a modification on emissions. These unit calculations are discussed first in this subsection; following this discussion, I explain the variety of emissions calculation comparisons (each of which utilizes these unit calculations) that one could consider in assessing PSD applicability. Although the regulations do not require all of these comparisons to be conducted in every case. I have presented an array of calculation types that could have been conducted by Duke pertaining to the modifications at issue. Finally, the

[30] Please note that in this context "unit" refers to the basic building blocks of the emissions calculations and tests – it should not be confused with the various generating units at specific Duke plants.

section concludes by describing the calculations I would recommend should have been performed for the PSD analysis.

Unit Calculation A – Actual Annual Average Emissions (tons/year)

For purposes of establishing baseline, actual annual average emissions in tons/year were calculated for each pollutant (NO_x, SO_2, and PM) for each modification at each unit (a) for the prior 24 month period preceding each modification; and (b) for the highest continuous 24 months out of the prior 60 months preceding each modification[31]. In each case, these emissions calculations were conducted as follows:

Actual Annual Average Emissions (tons/year) = Sum of relevant 24 Actual Monthly Average Emissions (tons/month) / 2;

where.

[31] For non-PMP units, the modification was usually accomplished in a particular outage and these time periods (i.e., prior 24 months or high 24 months in the preceeding 60 months) were identified based on the outage in which the modifications were accomplished. For PMP units, since they were usually shut down for fairly long periods of time (anywhere exceeding 3 to as many as 11 years), two sets of baseline calculations were conducted – the starting point in time for Baseline A (against which the prior 24 months as well as high 24 of prior 60 months time periods were identified) was the time when the unit was brought back into the generating mix after PMP; for Baseline B, the starting point in time was the estimated point in time within the PMP period when the major modifications were actually conducted. The establishment for the time frames for Baselines A and B were done per discussions with Mr. Robert Koppe as well as an analysis of coal use and generation data provided by Duke.

Actual Monthly Average Emissions (tons/month) = Actual Monthly Coal Usage (tons/month) x Emission Factor (lb/ton coal or lb/MMBtu) x Heating Value (Btu/lb coal, if needed) x 1/2000 (tons/lb).

For NO_x and SO_2, the Emission Factor, published in AP-42 or from Acid Rain data was used. In order to determine this factor, the actual monthly sulfur contents as provided by Duke were used. For PM, the emission factor from source tests was typically in units of lb PM/MMBtu of heat released. Thus, in addition to monthly coal use, I also used the monthly average heating value of coal (Btu/lb coal) also provided by Duke[32].

Unit Calculation B – Potential Annual Emissions (tons/year)

Potential annual emissions were calculated for all post-modification periods. In each case the emissions calculations were conducted as follows:

Potential Annual Emissions (tons/year) = Higher of Maximum Gross or Net Unit Capacity[33] (MW) x 8760 (hours/year) x Activity Conversion Factor (tons coal/MWg-hr) x Emission Factor (lb/ton coal or lb/MMBtu) x Heating Value (Btu/lb coal, if needed) x 1/2000 (tons/lb).

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[32] It should be noted that although other fuels were used at many of the Duke units – such as fuel oils for startup or even other materials such as used tires, etc., given the relatively minor amounts of heat generated by these materials as compared to coal, I have not considered these ancillary fuels in the present calculations.

[33] In several cases Duke reported Maximum Net Capacity that was higher than the Maximum Gross Capacity.

The activity conversion factor denoting the mass of coal necessary to generate each gross MW-hr of electricity was calculated for each unit from actual coal usage and actual gross generation (MW-hr). When using emission factors that fluctuated in time (due to varying actual sulfur contents or varying source tests for PM), I used maximum values of these parameters during the relevant time periods, when estimating the unit potential to emit for the respective pollutants. For situations where there were concurrent or anticipated low-NO_x modifications, in order to estimate future potential emissions for NO_x. I used the estimated lower-NO_x emission factor (typically assuming a 30% reduction in NO_x emissions from pre-modification conditions) consistent with the lower NO_x technology performance that Duke would have anticipated. Comparing NO_x emissions from acid rain data, this 30% reduction assumption is usually higher than what Duke in fact achieved after implementation of its various low NO_x projects. This method is therefore conservative, and results in an understatement of the likely NO_x emissions after the modification.

Unit Calculation C – Projected Emissions Increases (Derived from Duke Planning Documents)

For each of the modifications in question, Duke provided various documents and extensive planning projections that anticipated the impacts of the expected modifications, generally in terms of future projections of unit capacity factors for periods up to 10 years after the modification. These documents were analyzed by other

experts[34] and I was provided the expected annual future (for up to 10 years) capacity factors for that Duke had projected for each unit roughly prior to the modifications in each case. I used these capacity factor projections to first estimate future annual generation from each unit for specified future years as follows:

Future Annual Generation (MWhr/yr) = Unit Capacity Rating (MW) x 8760 (hours/yr) x Projected Capacity Factor for specified year (fraction)

I then used the following approach to estimate emissions corresponding to these future annual generation estimates as follows:

Future Annual Emissions (tons/year) = Future Annual Generation (MWhr/yr) x Activity Conversion Factor (tons coal/MWg-hr) x Emission Factor (lb/ton coal or lb/MMBtu) x Heating Value (Btu/lb coal, if needed) x 1/2000 (tons/lb).

In this case (as different from the potential to emit case discussed in Unit Calculation B earlier, I used the average values of sulfur content and PM source tests when developing the appropriate emission factors.

The "activity conversion factor" is the same as discussed earlier for the calculation of potential emissions earlier.

[34] See expert report of Mr. Biewald in this case.

Unit Calculation D – Projected Actual Emissions Changes Derived from GADS Data

Historical GADS data were analyzed by other experts[35] to determine the outages associated with specific boiler components that were later modified or replaced during each of the alleged modifications in this case. Details of how the GADS data were analyzed are provided elsewhere [see expert report of Mr. Robert Koppe]. Once the relevant GADS data were identified, activity factors such as generation utilization loss data was aggregated by month, as needed, and projected future actual emissions changes were calculated by summing the past actual monthly emissions attributable to the gross electricity generation loss activity factors discussed above for the same period. The presumption is that if the specific component causing the outage (which caused loss in unit utilization) was modified or repaired, the cause of the outage would be removed and the unit utilization would not be further impaired from that cause. As appropriate, the effect of the change on the pollutant emission factor was also considered. For example, when concurrent low-NO_x technologies were also installed at a particular unit during the same outage as an alleged modification, the NO_x emission factor was appropriately adjusted (i.e., lowered) in converting the GADS activity factor data to NO_x emissions.

Conversion of the GADS-derived gross electricity generation loss activity factor data (in gross MWhr/year) during specific annual time periods (e.g., for the immediate 24 months preceding a modification, or for the

[35] See expert report of Mr. Robert Koppe in this case.

emissions-based highest 24 out of the prior 60 months preceding a modification, etc.) to emission changes was performed as follows:

Emissions Changes Associated with GADS-Derived Generation Losses (tons/year) = GADS-Derived Generation Loss (gross-MWhr/yr) including Utilization Factor[36] x Activity Conversion Factor (tons coal/MWg-hr) x Emission Factor (lb/ton coal or lb/MMBtu) x Heating Value (Btu/lb coal, if needed) x 1/2000 (tons/lb).

The activity conversion factor is the same as discussed earlier for the calculation of potential emissions.

VI.1.2 PSD Emissions Comparison Tests

Once the unit calculations above were completed, they were combined to formulate various emissions comparison tests that one could have used to assess the applicability of PSD for the various modifications. Again, although the regulations do not require a source to conduct all of these comparison tests in every case, I describe a variety of possible comparison tests below. Some of these tests are not specifically contemplated by regulators but were nonetheless performed here to anticipate calculations or comparisons that might be offered by Duke (See Attachment G). Following this general discussion, I have identified the specific calculations or comparisons that, based on my experience, should have been performed for each modification.

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[36] The Utilization Factor was provided from Mr. Koppe. See his expert report for a discussion on the relevance of this factor and how it was estimated.

1. Prior Two Year Actual Average Emissions Versus Potential to Emit After Modification

In this method, the actual emissions for the prior 24 continuous months (two years) before the modification[37] were calculated and compared with the potential to emit for the unit after modification. In other words, the Unit Calculations A and B discussed earlier were performed and compared.

1a. Prior Highest Two of Five Year Actual Average Emissions Versus Potential to Emit After Modification

This is similar to Comparison Test 1 above; however, for the period prior to the modification, the highest actual emissions in any continuous 24 month period within the prior 60 months before the modification were compared to the PTE after the modification. The PTE calculation is the same as that in Comparison Test 1. It should be noted that the 24 month period in which the actual emissions may be highest can vary by pollutant – i.e., there can be three separate 24 month periods – one each for NO_x, SO_2, and PM within the prior 60 months of the modification. Also, it should be noted that for PMP units, two different baseline periods were identified as discussed earlier.

[37] The smallest calculation time period is a calendar month. It is also assumed that a particular modification was initiated and completed within a specific outage that began on a certain date and ended on a certain date. Depending on the starting date of the outage, either the previous full calendar month (if the outage began towards the beginning of a calendar month) or the month of the outage itself (if the outage began towards the end of a calendar month) was used as the last month before the outage.

2. Before and After Modification Emissions Difference Based on Company Capacity Factor Projections

In this method, the emissions "delta" is estimated by comparing the baseline emissions as calculated using Unit Calculation A (using the period 24 months prior to the modification for modifications when the WEPCO Rule did not apply or using the 24 month period within the prior 60 month period with the highest emissions for modifications when the WEPCO Rule applied) with the company projection calculations conducted using Unit Calculation C discussed earlier. In making this comparison, I used the company projections for future years 9 and 10[38] [in one case (Buck 3) only years 8 and 9 were available and in another case (Belews Creek Unit 2, 1999 Mod) years 8 and 9 were used since year 10 had a non-representatively low capacity factor presumably due to an anticipated turbine outage] with the prior 24 month baseline.

[38] The preferred choice to use years 9 and 10 (or 8 and 9 as noted above) for this comparison was made based on several considerations: (a) Duke had made projections as far as 10 years for a reason, namely that the 10 year planning horizon was a reasonable basis for future unit operations; (b) in the case of the PMP units, Duke's decision to gradually ramp up the unit capacities factors in the years following PMP (essentially converting these previously peaking or load-following units into base-loaded units as its system load increased) rendered the choice of other years (say years 1 and 2 or years 4 and 5, for example) moot since these other choices would not be compatible with how Duke intended to run the units in the foreseeable future; (c) years 9 and 10 were the farthest future years with forecasted capacity projections that shed light on Duke's intended plan for running its units; and finally, (d) consistency in using similar time frames for all units for purposes of making emissions estimates.

3. Emissions Change Based on GADS Activity Factor Data for Two Years Before Modification

In this method, the emissions change corresponding to a particular modification was directly estimated based on GADS-based activity factors such as recovered capacity, appropriately adjusted for capacity or utilization factor, as needed. In other words the Unit Calculation D discussed earlier was used to estimate this emissions change directly. For units that entered the PMP program, GADS loss data are often sparse. This is because, even prior to entering PMP, these units were not running very often and, there was ample opportunity to make relevant repairs to components, as needed, during such downtime.

VI.1.3 Discussion

The calculation comparison tests provided above for PSD are not exhaustive; rather, they are examples of plausible approaches that could have been used by Duke to assess the impacts of the various modifications on the emissions from its various units.[39] I am certainly not suggesting that all of these tests should have been performed. However, based on my experience, *some* of these tests should definitely have been performed, in all cases

[39] It should be noted that netting calculations, although allowed by the PSD regulatory program, were not performed because the data required for performing such calculations, although requested from Duke, had not been received. Duke has not provided information on what it considers to be contemporaneous increases and decreases relevant to this calculation. However, as noted in the text, netting was implicitly considered when contemporaneous (i.e., at the same time as the modifications) emissions decreases were obtained (for NO_x) due to the installation of low- NO_x technologies. These emissions decreases were, of course, accounted for in the calculations.

because they are consistent with regulatory requirements and because they would have indicated to Duke the likelihood of triggering PSD. Had there been inconsistent conclusions from these tests, more evaluations may have been performed and the need for consultation with regulators may have been identified. Specifically, the following three comparisons should have been performed for assessment of PSD applicability.

A. Generally (and certainly for modifications which did not qualify for WEPCO either because they undertaken prior to the July 1992 WEPCO decision or because the North Carolina SIP at the time of the modification did not contain the WEPCO provision, as discussed in Section IV.2). the actual-to-potential test using a prior 24 month baseline for non-WEPCO Rule modifications or highest 24 month out of the prior 60 months on an emissions basis for WEPCO Rule modifications (Comparison Test 1 discussed above) should have been done to assess regulatory applicability. Even if the WEPCO Rule could have applied the use of this test is not precluded. As discussed earlier, although utilities were allowed to use the "actual to future actual" test under the WEPCO Rule, they could only do so if they also submitted annual actual emissions or utilization data for 5 years after the change. This data would have confirmed Duke's initial projections of an emissions decrease after a non-routine change, Duke has not submitted such data for this purpose to the relevant agencies (i.e., North Carolina state regulators or EPA). Therefore, I have considered this test for all of the alleged modifications.

B. The company's own projections of the benefit or goal of the modification in terms of increased capacity projection (and generation) could have been used to estimate future emissions. Thus, Comparison Test 2 discussed above could have been directly used to initially estimate the increases in pollutant emissions caused by with a particular modification.

C. Finally, particularly for the time periods when WEPCO applied, Comparison Test 3 should have been performed, for several reasons. First, GADS activity factor data was readily accessible to Duke since they were in fact reporting the GADS performance and event data to the North American Electric Reliability Council (NERC). Second, the direct relationship of GADS activity factor data to the modifications, and their relevance and usefulness as a predictor of future availability and utilization, further enhances the utility of GADS data for identifying the effect of a modification on emissions. From that standpoint, the GADS data provide an excellent set of activity factors directly relevant to the causal aspects of the modifications[40] in so far as future emissions predictability

[40] NSR generally does not apply unless there is a causal link between the modification and the post-modification emissions increase (see WEPCO Final Rule, July 1992, Section C). For example, as stated in the July 21, 1992 WEPCO Final Rule Section C. " . . . where increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and affected the unit's operations even in the absence of the physical or operational change, such increases . . . shall be excluded from the projection of future actual emissions." As a general matter, given the nature and extent of the changes, at the various Duke units the projected growth in capacity utilization could not have been possible but for the physical changes alleged in the present proceedings. Hence, all emissions that were causally linked to modifications were considered. The GADS based comparison test is particularly useful in establishing this causal link.

is concerned. And, finally, Duke itself was using GADS data for the purposes of calculating emissions and making PSD applicability determinations[41]. While GADS is not explicitly referenced in EPA's PSD regulations, those regulations do not disallow its use either. PSD regulations apply to all industries and these industries have different measures of activity factors. Because it is not possible for the regulations or for regulatory guidance to anticipate all of the types of process data or activity factors from all industries that might conceivably be used as a basis for emissions calculations, there is no reason to believe that the use of GADS data would have been disfavored by any state agency or EPA.

The emissions comparison results, for each modification, of each test discussed above, is shown in the Table below. Attachments F and G, respectively, show the summary results and the detailed calculations for each test for each modification. In addition to the table below and the calculations in Attachments G, I have also provided an example of the types of graphs that can be generated from the data (baseline actual, future projected, and potential to emit) shown in Appendix G. The example, in Figure 1, is for SO_2 emissions from Dan River Unit 3.

[41] See, for example, memo in Bates 30B5E 0000002, dated 5/23/97.

Table 1 – Summary Emissions Increase Results (Tons/Yr) for PSD Applicability

Modification/ Comparison Test	Pollutant[1]			
	SO_2	NO_x	PM	PM_{10}[2]
PSD Significant Emissions Rate (SER)	*40*	*40*	*25*	*15*
Modification #6 – Allen 1 (1989)				
Comparison Test 1	11496.5	4538.1	1527.7	1023.6
Comparison Test 2	3430.4	1857.1	620.3	415.6
Comparison Test 3	55.7	30.1	10.1	6.8
Modification #5 – Allen 2 (1988)				
Comparison Test 1	12559.4	4957.7	2782.4	1864.2
Comparison Test 2	2991.6	1610.3	690.1	462.4
Comparison Test 3	34.2	17.7	6.8	4.6
Modification #23 – Allen 3 (1994)				
Comparison Test 1	15845.6	2377.0	1468.4	983.8
Comparison Test 2	1705.0	–	237.4	158.58
Comparison Test 3	21.5	5.6	1.6	1.1
Modification #3 – Allen 4 (1996)				
Comparison Test 1	13594.2	2235.0	773.4	518.2
Comparison Test 2	260.1	–	–	–
Comparison Test 3	195.3	65.0	11.3	7.6
Modification #4 – Allen 4 (1996)				
Comparison Test 1	11124.6	2751.0	1330.3	891.3
Comparison Test 2	2114.6	872.9	597.0	400.0
Comparison Test 3	150.3	60.6	14.5	9.7
Modification #2 – Allen 5 (1996)				
Comparison Test 1	14294.1	2210.9	1718.2	1151.2
Comparison Test 2	3324.4	191.2	408.7	273.8
Comparison Test 3	234.3	79.4	27.8	18.6

Modification #1 – Allen 5 (2000)				
Comparison Test 1	8153.1	2395.1	–	–
Comparison Test 2	880.0	481.3	–	–
Comparison Test 3	229.7	89.0	10.0	6.7
Modification #9 – Belews Creek 1 (2000)				
Comparison Test 1	14909.3	–	–	–
Comparison Test 2	–	–	–	–
Comparison Test 3	1319.8	537.2	35.5	23.8
Modification #8 – Belews Creek 2 (1996)				
Comparison Test 1	33644.4	22678.3	1077.5	721.9
Comparison Test 2[3]	–	–	–	–
Comparison Test 3	202.0	222.5	8.7	5.8
Modification #7 – Belews Creek 2 (1999)				
Comparison Test 1	15719.2	–	–	–
Comparison Test 2[4]	–	–	–	–
Comparison Test 3	331.3	147.3	11.0	7.4
Modification #12 – Buck 3 (1994)				
Comparison Test 1	6208.8	3063.6	369.4	247.5
Comparison Test 2	873.4	278.7	44.6	29.9
Comparison Test 3	0.0	0.0	0.0	0.0
Modification #11 – Buck 4 (1994)				
Comparison Test 1	2981.3	1471.0	169.3	113.4
Comparison Test 2	827.3	264.0	36.7	24.6
Comparison Test 3	4.8	2.4	0.2	0.1
Modification #10 – Buck 5 (1991)				
Comparison Test 1	9767.9	3855.8	387.1	259.4
Comparison Test 2	2415.9	1223.9	87.8	58.8
Comparison Test 3	97.7	49.5	3.6	2.4

Modification #28 – Buck 6 (1990)				
Comparison Test 1	9678.2	3179.8	249.5	167.2
Comparison Test 2	361.1	356.3	2.1	1.4
Comparison Test 3	50.0	33.2	2.0	1.3
Modification #21 – Cliffside 1 (1993)				
Comparison Test 1	6267.9	2249.2	503.8	337.5
Comparison Test 2	528.8	272.2	51.4	34.4
Comparison Test 3	2.7	1.4	0.3	0.2
Modification #17 – Cliffside 2 (1993)				
Comparison Test 1	5468.3	2158.5	759.8	509.1
Comparison Test 2	641.1	308.3	108.6	72.8
Comparison Test 3	0.0	0.0	0.0	0.0
Modification #18 – Cliffside 3 (1991)				
Comparison Test 1	9183.8	3295.6	862.2	577.7
Comparison Test 2	960.4	429.2	110.7	74.2
Comparison Test 3	45.2	20.2	5.2	3.5
Modification #19 – Cliffside 4 (1991)				
Comparison Test 1	6525.7	2341.8	637.5	427.1
Comparison Test 2	771.9	395.3	89.1	59.7
Comparison Test 3	5.7	2.9	0.7	0.5
Modification #20 – Cliffside 5 (1992) [4]				
Comparison Test 1	30934.4	10164.1	1339.1	897.2
Comparison Test 2	10339.1	4394.2	53.1	35.6
Comparison Test 3 [4]	0.0	0.0	0.0	0.0
Modification #20 – Cliffside 5 (1995) [4]				
Comparison Test 1	24077.8	3098.8	2496.1	1672.4
Comparison Test 2	5687.6	2464.6	–	–
Comparison Test 3	177.7	48.3	14.1	9.4

Modification #22 – Dan River 3 (1998)				
Comparison Test 1	10755.8	4245.7	609.7	408.5
Comparison Test 2	2160.0	1065.8	147.3	98.7
Comparison Test 3	617.9	304.9	51.2	34.3
Modification #29 – Marshall 1 (1992)				
Comparison Test 1	14217.7	4581.1	272.5	182.6
Comparison Test 2	4067.5	1491.3	–	–
Comparison Test 3	212.9	83.3	8.4	5.6
Modification #15 – Marshall 2 (1989)				
Comparison Test 1	14146.0	4456.2	1198.9	803.3
Comparison Test 2	2690.8	1091.9	42.3	28.3
Comparison Test 3	873.2	358.1	62.2	41.7
Modification #16 – Marshall 2 (1996)				
Comparison Test 1	10356.4	373.6	1673.7	1121.4
Comparison Test 2	5233.8	–	924.8	619.6
Comparison Test 3	131.3	37.0	9.1	6.1
Modification #14 – Marshall 3 (1999)				
Comparison Test 1	19530.2	4107.9	466.4	312.5
Comparison Test 2	502.2	188.3	88.4	59.2
Comparison Test 3	793.7	280.9	19.5	13.4
Modification #13 – Marshall 4 (1990)				
Comparison Test 1	22399.4	7166.8	2569.2	1721.4
Comparison Test 2	7347.2	2897.7	942.2	631.3
Comparison Test 3	1299.7	518.2	113.4	76.0
Modification #24 – Lee 3 (1989/90)				
Comparison Test 1	9861.7	3387.2	227.5	152.4
Comparison Test 2	488.2	380.9	17.5	11.7
Comparison Test 3	162.8	78.7	4.6	3.1

Modification #25 – Riverbend 4 (1990)				
Comparison Test 1	8691.3	2859.0	137.8	92.3
Comparison Test 2	1582.2	715.6	35.6	23.9
Comparison Test 3	93.6	42.3	2.1	1.4
Modification #26 – Riverbend 6 (1991)				
Comparison Test 1	15395.7	5064.4	482.9	323.5
Comparison Test 2	2066.9	1247.2	102.0	68.3
Comparison Test 3	312.7	188.7	15.4	10.3
Modification #27 – Riverbend 7 (1992)				
Comparison Test 1	10678.6	3512.7	340.1	227.9
Comparison Test 2	4215.2	1650.1	136.7	91.6
Comparison Test 3	313.1	122.6	10.2	6.8

Notes:

[1] "–" denotes a negative value or reduction in the comparison for that case. In many such cases, the NO_x comparisons show a reduction because of the installation or planned installation of low-NO_x technologies at that unit that were factored into the calculations of future projected NO_x emissions. PM emissions were somewhat erratic given the significant variability in the annual PM source test results that were used in the calculations.

[2] PM10 was estimated as 67% of PM emissions, per AP-42. Table 1.1-6.

[3] For this modification, it should be noted that its capacity factor in the baseline year as well as in the projection years was generally high given that it is a base loaded unit. For example its baseline year capacity factor was around 73% while its average post-mod year 1/2 and year 9/10 capacity factor projections were 76% and 78.5%, respectively. Even though there is a capacity factor increase, there appears to be a reduction in the projected

SO_2 emissions in the projected years as compared to the baseline period because the sulfur content in the coal in the baseline period (i.e., 24 month period with the highest SO_2 emissions for this potentially WEPCO Rule-eligible unit) was higher (i.e. 0.99%) than in the years preceding the modification (0.83%) and the latter was used to make the future projection, giving Duke the benefit of lower sulfur content in the future, even though this lower sulfur content is not enforceable via permits or other means. If, on the other hand, an average sulfur content for the entire 5 year period preceding the modification (0.89%) is used for all calculations (i.e., baseline actual and future projections, there would be an *increase* in Comparison Test 2 for this case.

[4] Although the complaint listed the modification as having occurred in 1992 and 1995, emissions calculations are provided for both 1992 and 1995 changes separately. The lack of GADS based losses attributable to the economizer prior to the 1992 modification (in which the economizer was replaced given its documented [see Bates 62CS001] poor performance in preceding years) needs further discussion. Closer inspection of the GADS data show that this base load, low heat rate (i.e., economically efficient) unit was not operating for a significant portion of time preceding the 1992 modification and was listed as being in reserve shutdown. It is possible that repairs to the malfunctioning economizer were made during periods of reserve shutdown and therefore such periods of time did not get attributed to the economizer repair.

VII. RESULTS OF EMISSIONS CALCULATIONS

The summary and detailed results of the various emission calculation approaches discussed above for PSD are provided in Attachments F and G for each of the modifications relevant to the present proceeding. All supporting documents used in the emissions calculations are referenced in the calculation tables in Attachment G.

VIII. CONCLUSIONS

Based on the foregoing analysis, and given the extensive nature of the modifications and/or change in the method of operation of the various Duke units that are the subject of this litigation, it is my opinion that Duke should have applied for and obtained PSD permits prior to undertaking the modifications and/or change of method of operation at its respective units.

Figure 1 - Dan River 3 (1988) - SO2 Graph

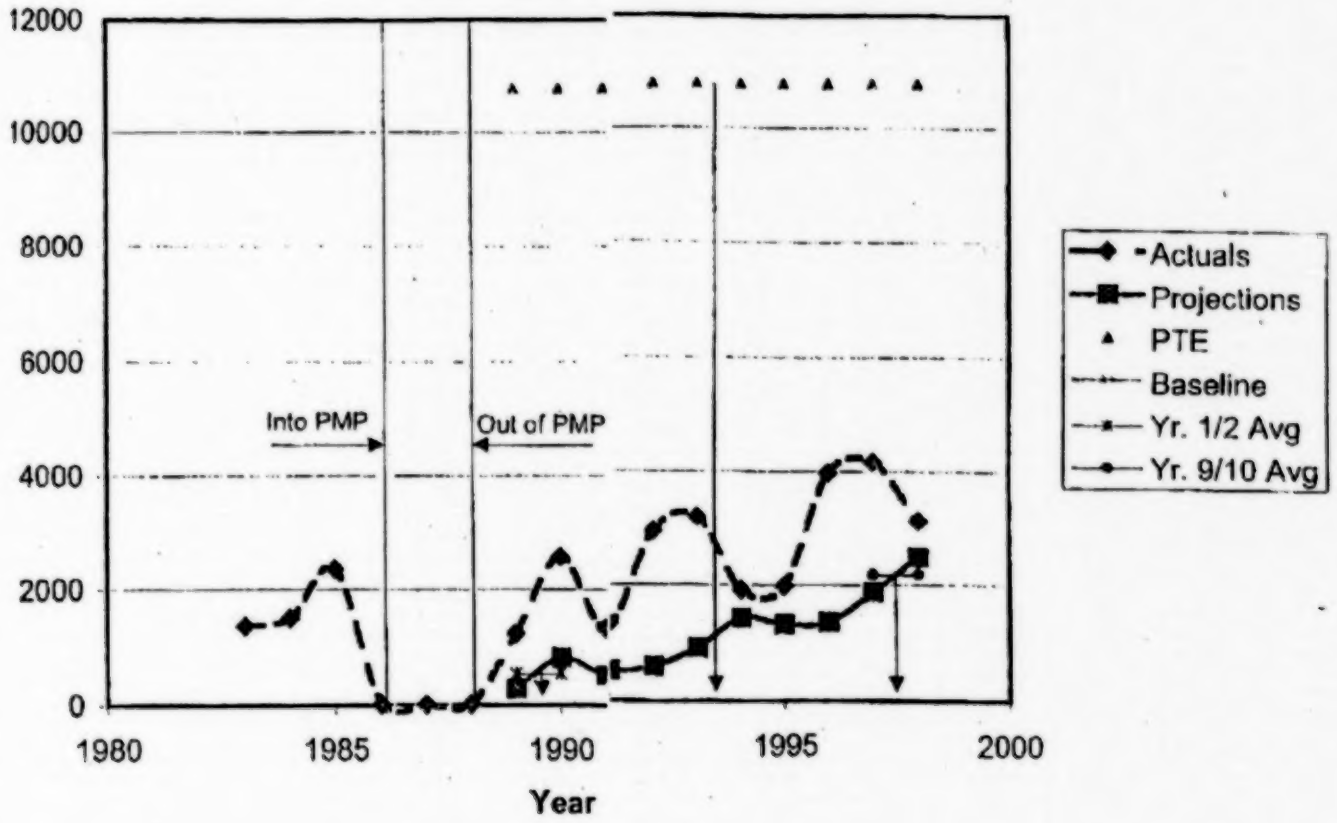

Figure 2 - Allen 5 (1996) - SO2 Graph

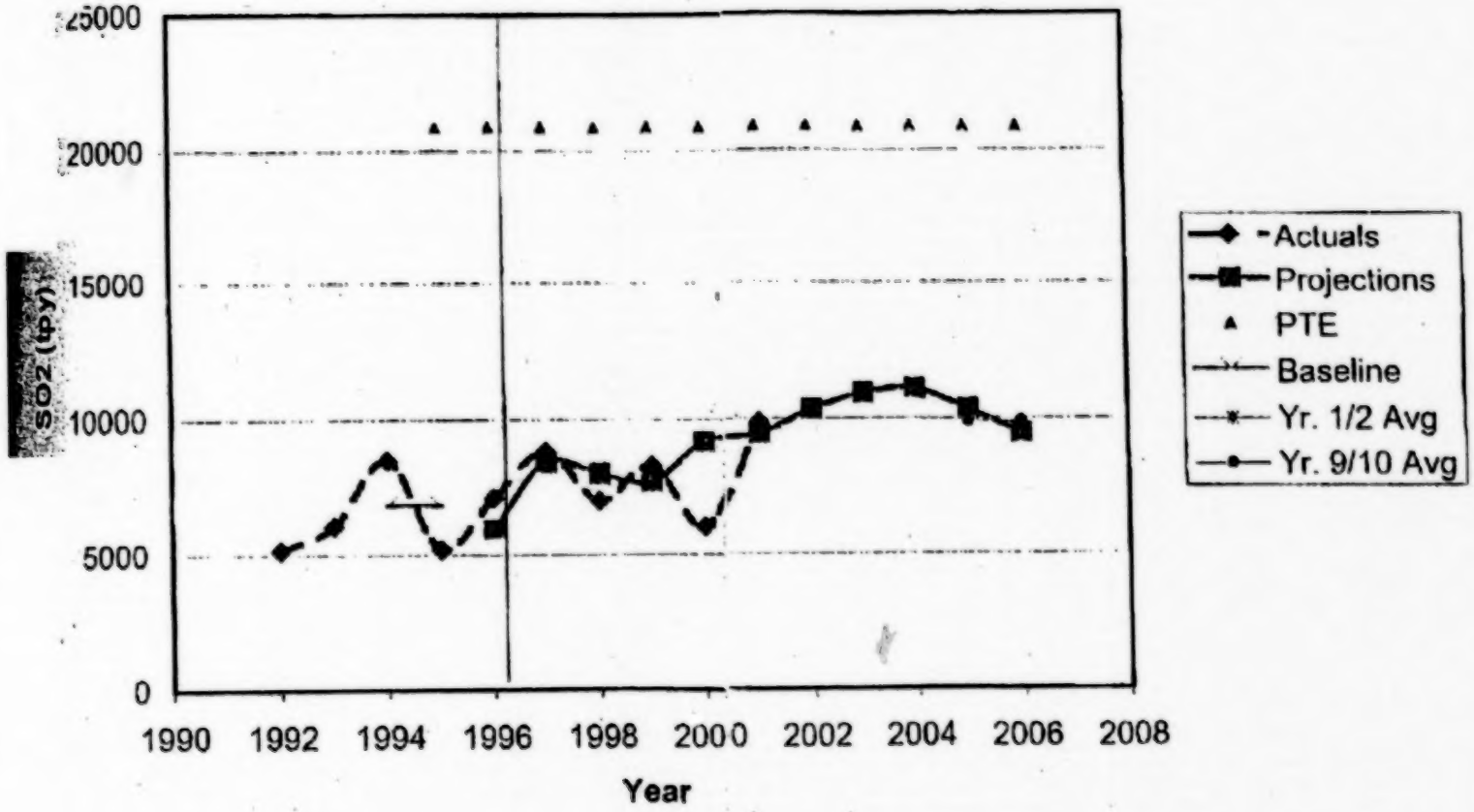

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EXHIBIT 162

BEFORE THE
UNITED STATES OF AMERICA
ENVIRONMENTAL PROTECTION AGENCY

Docket No. A-90-06

Statement of Henry V. Nickel, on behalf of the Utility Air Regulatory Group, on EPA's Proposed Rule on New Source Review and Confirmation of Existing Law

Introduction

My name is Henry V. Nickel. I am a partner with Hunton & Williams in Washington, D.C. I am appearing here today on behalf of the Utility Air Regulatory Group (UARG), an *ad hoc* organization of 71 individual electric utilities, as well as the three industry trade associations. Since 1970, I have represented clients, including UARG, in virtually every significant Clean Air Act rulemaking involving the regulation of major stationary sources. I also represented Wisconsin Electric Power Company in litigation before the U.S. Court of Appeals for the Seventh Circuit that culminated in the so-called "*WEPCo*" decision.

Before turning to the specifics of EPA's proposed rule, I would like to address two broader issues that UARG believes are important in assessing the proposed rule and its preamble in general.

First, as whole, the proposed rule and its preamble send a welcome signal to the electric utility industry that EPA has moved away from those interpretations of its New Source Review (NSR) rules – its so-called "WEPCo interpretations" – that have cast a considerable "cloud" over pollution control projects and other legitimate utility

activities at existing sources. In this regard, the proposed rule and preamble recognize that EPA's NSR provisions have *never* contemplated that every activity that would lead to an emission increase should trigger NSR. For instance, from their inception, the NSR rules have excluded whole categories of activities at existing sources, such as "routine maintenance, repair, and replacement," or emission increases resulting from increases in hours of operation or production rate. Generally, these exclusions apply to activities that would be expected to occur at existing sources during their useful life and therefore are consistent with their continued grandfathered status.

Second, and relatedly, the proposed rule should be viewed as giving effect to the plain meaning of existing law, not as an expression of new law. Indeed, in contrast to EPA's "WEPCo interpretations," the view of current law contained in the preamble to the proposed rule is in line with the agency's own historic understanding of its NSR rules.

Pollution Control Projects

Consistent with its original interpretation of the NSR rules, EPA's notice makes clear that most, if not all, pollution control projects are excluded from NSR. Only where EPA finds that a pollution control replacement project would make a unit "less environmentally beneficial" would NSR apply.

While we are pleased with EPA's decision to remove the *WEPCo* "cloud" that has threatened timely and successful efforts by the utility industry to meet the requirements of Title IV, we do not believe that, as a matter of law, *any* change in EPA's rules is necessary. Since the early

1970's, the New Source Performance Standards (NSPS) rules have excluded pollution control projects from the definition of "modification" unless the replacement of such pollution controls rendered the unit "less environmentally beneficial." In 1977, when the Clean Air Act was amended to include the NSR provisions, Congress provided that the term "modification" was to have the same meaning as under the NSPS program. Further, in 1983, EPA determined that environmentally beneficial pollution control projects are excluded from NSR. The interpretation of current law announced by EPA in its recent notice is consistent with the Act and the agency's earlier determination.

Thus, while we support the intent of EPA's proposed rule on pollution control projects generally, we do not believe that this rule is in fact needed. But if such a rule is to be adopted, it should not be restricted to pollution control projects in the electric utility industry. Such a restriction cannot be logically reconciled with the EPA's own understanding of its NSR rules or with Congress's intent in enacting the NSR program.

"Actual-to-Actual"

We support EPA's affirmation that the "linchpin" for deciding whether to use "future actual" or "future potential" emissions in calculating an emission increase is whether the unit has "begun normal operations." 56 Fed. Reg. 27,633 (June 14, 1991). EPA's NSR rules allow for the comparison of "past actual" emissions to "future potential" emissions only where a unit has "not begun normal operations." Where normal operations have begun, the "actual-to-actual" approach applies.

EPA strayed from the proper interpretation of its NSR rules with its so-called "WEPCo interpretations." EPA's notice constitutes a welcome return by the agency to the correct view of the law.

With respect to determining the pre-change baseline for making the "actual-to-actual" comparison, EPA notes that, historically, it has used the two years immediately preceding the proposed change to establish the baseline. While EPA proposes to retain the current regulatory language, it has announced a new presumption that "any 2 consecutive years within the 5 years prior to the proposed change is representative of normal source operations for a utility." 56 Fed. Reg. 27,636 (June 14, 1991). We believe that, in order to allow for the establishment of a truly "representative" baseline period, EPA should clarify its presumption to provide for the use of any two consecutive years within the last five years of *operations*. This would allow for the establishment of a more representative baseline for units that have been in a lengthy shutdown.

"Causal Link" Requirement

In its notice of proposed rulemaking, EPA points out that, under the plain language of its NSR provisions, the physical or operational change must "result in" an increase in actual emissions in order to consider the change a modification. Thus, EPA recognizes that emission increases must be causally linked to the physical or operational change. EPA continues that, where "increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and affected the unit's operation, such increases do not result from the change and shall be excluded from the

projection of future actual emissions." 56 Fed. Reg. 27,63 (June 14, 1991).

We agree with EPA's application of the causal lin requirement to utility operations. We note, moreover, tha excluding load growth from emission increase calculation at units that have begun normal operations is also re quired under the "production rate/hours of operation exclusion in 40 C.F.R. § 52.21(b) (2) (iii) (f).

Calculation of NSPS Baseline

We generally support EPA's proposal to amend it NSPS rules to use a five-year period prior to a physical o operational change in calculating the baseline for deter mining maximum hourly emissions. Again, EPA's propose change is consistent with past practice, since it recognize that, where temporarily lowered emissions immediatel before a physical or operational change are not representa tive of emissions after the change, such lowered emissio levels should not be used.

We believe, however, that EPA's rule should be clar fied to provide for the establishment of a baseline on th basis of the last five years of the unit's *operations*. Such change is necessary if the unit's baseline is truly to b "representative of [the unit's] physical and operationa capacity in recent years. . . . " 56 Fed. Reg. 27,638 (Jun 14, 1991). Also, we do not believe that there is any basi for EPA to restrict its proposed rule to electric utility unit only.

BACT Presumption for NOx Controls

We support EPA's proposal to adopt a presumption that "best available control technology" (BACT) for emission of nitrogen oxides (NOx) is low NOx burners or some similar cost-effective technology. We agree with EPA that this presumption is appropriate given the strong congressional policy judgment favoring the use of low NOx burners for NOx control at existing units under Title IV.

Effect on Local Air Quality

Contrary to some criticisms that have been leveled against EPA's proposed rule, we believe it important to recognize that the proposed rule does nothing to authorize increases in emissions that threaten local air quality. A source's obligation to meet ambient requirements is independent of any obligation to meet NSR requirements. That an increase in emissions is found not to be a modification does not in any way authorize the source to exceed Prevention of Significant Deterioration (PSD) increments, ambient standards, or a visibility related limitation. Nor would an increase in utilization of a unit be expected to threaten compliance with ambient requirements. Most if not all emission limitations implementing ambient standards or PSD increments are based on annual emission factors that represent operations 365 days a year at maximum production levels.

As already noted, EPA has never considered its NSR program as addressing every type of activity within industry that potentially increases emissions. Small sources are not covered by the NSR provisions. The rules themselves exclude from the modification definition a variety of activities that can result in emission increases.

For instance, emission increases attributable to increases in a unit's hours of operation or production rate (*i.e.*, annual utilization) are excluded. In this regard, in developing the Administration's proposal on acid rain legislation, EPA projected substantial increases in utilization of units over the next 10 years and predicated, at least in part, the need for a SO_2 cap on these projections. Any claims that increases in utilization of existing utility units are for the first time authorized by this notice (*i.e.*, were somehow prohibited before this notice) have no basis in fact or law.

Conclusion

We support EPA's decision to confirm and clarify existing law, which should further the efforts of the electric utility industry to meet the goals of Title IV in an effective and timely manner. UARG will be submitting more detailed written comments on the proposed rule by the end of the comment period.

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA,	)	
Plaintiff,	)	
v.	)	CIVIL NO. 1:00CV1262
DUKE ENERGY CORPORATION,	)	
Defendant.	)	

SUPPLEMENTAL EXHIBITS IN SUPPORT OF
DUKE'S MOTION FOR SUMMARY JUDGMENT

(Filed Mar. 31, 2003)

* * *

Report to the Public Staff
North Carolina Public Utilities Commission

The Duke Power Company's
Plant Modernization Program (PMP)
and Catawba Unit 2

Volume II: Analysis of Life Extension

Prepared by:
The S. M. Stoller Corporation (SMSC)
1919 14th Street, Suite 500
Boulder, Colorado 80302
(303) 449-7220

August 19, 1986

Primary Authors:

Kenneth R. Van Howe
Robert H. Koppe

* * *

1.5 SUMMARY OF FINDINGS

The results of our evaluations of the current status of th equipment at the PMP units, the current Plant Modern zation Program, the EUORs for the units and specifi alternate scenarios for the Plant Modernization Prograr are described in the subsequent sections of this report. Th overall findings of this work relative to answering the fou questions identified above in OBJECTIVES are as follows:

1. Although the individual PMP units are in need of repair and upgrade, the condition of the units would not preclude any of them from being operable, albeit at reduced reliability and, in some cases, with additional restrictions on maximum output or limited

start-stop cycles prior to completion of the upgrade work.

2. If, in late 1982/early 1983, Duke Power Company had initiated an aggressive program to upgrade these twelve PMP units, it would have been possible to have the upgrade work critical to reliable operation for Dan River 3, Riverbend 6, and Riverbend 7 completed in 1985 (408 MW); Allen 1 and Buck 5 completed in 1986 (278 MW); Buck 3, Buck 4, Cliffside 3, and Cliffside 4 in 1987 (230 MW); Allen 2, Cliffside 1, and Cliffside 2 in 1988 (226 MW). In order to achieve this aggressive program additional costs would be incurred due to the need to perform the work on a two shift basis using a significant amount of contract labor. The additional costs would amount to about $22 million.

3. The repairs and upgrades contained in Duke's PMP appear, in general, to be reasonable based upon the current condition of the units. There is greater uncertainty in the repairs and upgrades required on units for which a detailed upgrade study has yet to be performed (PMP units at Buck, Riverbend and Cliffside). The assumption in the Duke program that all 19 suspect turbine and generator rotors will require replacement at a cost of $72 million is highly conservative. Some of the rotors have not been inspected by boresonic tests and may be in good condition. Even with unfavorable boresonic tests, they may be repairable by overboring or bottle-boring. In the case of some of the smaller non-reheat units (particularly Buck 4 and Cliffside 1 and 2), the cost of rotor replacement may be prohibitive in relation to

the value of the units and if the rotors can not be repaired, it may be preferable to retire the units or to operate them with a frequent inspection cycle with limitations on the number of start-stop cycles prior to reinspection.

* * *

Operability of Units

All of the units in the current PMP could be made operable with modest expenditures and retained in an operable condition during the upgrade effort. In some cases, such as Allen 1 and 2, the maximum dependable capacity of the units would have to be reduced until the precipitators are replaced. In other cases, such as Buck 3 and 4, the number of start-stop cycles on the unit would have to be restricted until the turbine generator rotors are repaired or replaced. In most units, the reliability and heat rate of the units would be significantly degraded until the upgrade work is performed.

Faced with the current situation of not needing the units to meet system load and with Catawba 2 coming on-line in 1986, placing the units in an extended cold shutdown condition can be cost effective since operations and maintenance costs can be reduced and upgrade work can be performed as maintenance personnel are available.

Replacement of Rotors

The assumption that all turbine and generator rotors that have not been verified to be in good condition using boresonic techniques require replacement is highly conservative. The program calls for the replacement of 19 rotors at a total cost of $72 million (See Table II-2.5) which is 45%

of the total cost of the total upgrade program at these twelve units. Ten of these rotors have not been boresonically tested and it is not known if any serious indications are present. One might suspect some level of indications of cracks in the rotor material due to the age and service conditions (cycling) to which these rotors have been subjected. Bottle-boring and overboring has been successful in many instances in removing the bore indication yielding a rotor which should be serviceable for an additional 20-year life. The Dan River 1 and 2 generator rotors, the Dan River 2 LP turbine rotor, the Cliffside 3 LP rotor and the Cliffside 4 HP rotors have been successfully overbored or bottle-bored to remove indications. Overboring of the Cliffside 4 LP rotor should remove any indications. Duke feels there is some chance of saving the Buck 3 generator rotor and the Riverbend 6 IP/LP rotor. Although it is not possible to say how many of the 19 rotors can be saved, it is very conservative to assume that all will require replacement.

* * *

EXHIBIT 129

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 28 1983

OFFICE OF
AIR, NOISE AND RADIATION

SUBJECT: Bridgeport Harbor Coal Conversion

FROM: Director
Stationary Source Compliance Division
Office of Air Quality Planning and Standards

TO: Harley Laing, Director
Air Management Division, Region I

This is in response to your June 8, 1983 request for an applicability determination concerning the conversion to coal of Bridgeport Harbor Unit #3. Your opinion is that the conversion should not be subject to either PSD or NSPS requirements because you feel the boiler was originally designed to burn coal, and as such is exempt under § 60.14(e)(4) from NSPS coverage and under § 52.21(b)(2)(iii)(e)(1) from PSD coverage. You asked for our concurrence in this opinion.

United Illuminating Company (UI) wants to burn coal in its 400 MW capacity Bridgeport Harbor Unit #3 (it currently burns oil) and requests your determination that such a conversion is exempt from NSPS and PSD applicability. UI contends that the unit was originally designed to accommodate coal, and has supplied copies of the original proposal, contract and designs to support this position. Even though a decision was made in 1967, during the latter stages of construction, to use oil as the primary fuel, no coal-firing equipment was deleted from the contract

and all equipment contracted for was installed. Additionally, coal handling facilities, pulverizers, ash and slag handling equipment and all other systems and equipment required for pulverized coal firing of the unit were installed.

Since coal was never burned in the unit, changes are now necessary to enable its use. Such changes include modifications to tubing within the boiler, the addition of flame scanners, burners, ignitors and relays, and piping and wiring to allow for bottom ash removal. In addition, the pulverizers must be made functional. These changes to the steam generating unit are estimated to cost approximately 5 million dollars.

The NSPS for electric utility steam generating units, 40 CFR 60, Subpart Da, provides an exemption from coverage for conversion from oil to coal. See §60.40a(d):

> Any changes to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

A less inclusive provision exempts coal conversions from Subpart D NSPS applicability if the existing facility was designed to accommodate coal before August 18, 1971. See §60.14(e)(4), which exempts from the modification provisions:

> Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or

raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change.

Bridgeport Harbor Unit #3 is exempt from Subpart D coverage because of the provision at §60.40a(d). My staff has examined the conversion as related to Subpart D applicability, and discussed it with EPA's Emission Standards and Engineering Division (ESED). The construction specifications for unit #3 outlined in your memorandum clearly indicate that the unit was designed to accommodate coal prior to the Subpart D applicability date, even though coal was never burned. Also, the approximately million dollars which UI must spend on the affected facility, the steam generating unit, to enable it to actually burn coal, is minimal compared to the costs of a coal conversion, and represents only minor adjustments to equipment already in place. For these reasons, both SSCB and ESED concur with your conclusion that Unit #3 is exempt from coverage under Subpart D as well as Subpart Da.

The question of PSD applicability is more difficult because it is necessary to determine if the entire plant rather than simply the boiler, was capable of accommodating coal before the January 6, 1975 applicability date. In a telephone conversation on July 19 1983 between Robert Myers of my staff and John Courcier of your office, John related to Bob the extent to which UI has incorporated coal capability at their Bridgeport Harbor Station. Apparently UI has already put in place, prior to January 6 1975, all of the coal handling and support facilities necessary for the combustion of coal. This equipment continues to be available and only requires some minor adjustment in order to accommodate coal at Unit #3. Therefore, it is

the opinion of this office that UI's Bridgeport Harbor Station was capable of accommodating the alternative fuel prior to January 6, 1975, and is exempt from the PSD permitting requirements pursuant to §52.21(b)(2)(iii)(e)(1).

This response has received the concurrence of both OAQPS and the Office of General Counsel. Please contact Robert Myers at FTS 382-2875 if you have additional concerns.

/s/ Edward Reich
Edward E. Reich

cc: Jack Farmer
Walt Stevenson
Earl Salo
Dave Rochlin
Mike Trutna
Peter Wyckoff

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

DATE: June 8, 1983

SUBJECT: PSD Applicability for Bridgeport Harbor Coal Conversion

FROM Harley F. Laing, Director /HL/
Air Management Division Region I

TO Edward E. Reich, Director
Division of Stationary Source Enforcement

Issue

Region I requests your concurrence in our determination that the Bridgeport Harbor Unit #3 is not subject to either PSD or NSPS requirements. It is our belief that the boiler

was originally designed to burn coal and the changes that are being under-taken at UI's Bridgeport Harbor station do not constitute a major modification as defined under PSD and NSPS, and therefore, should be exempt from these reviews.

Background

The United Illuminating Company (UI) has filed an application with the Connecticut Department of Environmental Protection (CT DEP) to burn coal in Unit #3 (BHS 3) at UI's Bridgeport Harbor Station. The CT DEP issued UI an operating permit for BHS 3, and has since requested that Region I determine whether or not the coal conversion at BHS 3 (which was originally designed to burn coal) should be considered a modification and therefore subject to the PSD and/or the NSPS regulations (40 CFR Part 60, Subparts D and Da).

UI contends that BHS 3 was originally designed to accommodate coal. In fact, they have supplied the CT DEP with copies of the original proposal, contract, and designs which indicate that coal was indeed intended to be the primary fuel. During the latter stages of the construction in 1967-1968, a decision was made to use oil as the primary fuel and coal as a secondary fuel. However, no coal firing equipment was deleted from the contract and all coal firing equipment contracted for was installed. In addition, all of the other systems and equipment required for pulverized coal firing of the unit, including coal handling facilities, pulverizers and ash and slag handling equipment, were similarly specified by UI and installed by UI's contractor.

At a state investigative hearing on the coal conversion, certain additional facts were revealed. Although UI showed that the boiler was originally designed and built to burn either coal or oil, significant heat exchange surface alterations were made to allow for continuous, long-term oil burning. Coal has never been burned in the BHS 3. Some modifications to BHS 3 are now necessary in order to allow for continuous, reliable coal burning at partial load or oil at full load, including modifications to tubing within the boiler, as well as to some of the auxiliary equipment. Other changes to the unit include the addition of flame scanners, burners and ignitors, and additional relays. Certain piping and wiring to allow the bottom ash removal system, certain coal handling equipment and the pulverizers to be functional is also necessary. Additional equipment modification would have been necessary in 1968 to burn coal, but because oil was to be used as fuel, such modifications were never fully completed. Although the state hearing officer concluded that extensive "physical changes and additions" to the BHS 3 totalling some $35 million constitute a modification to a stationary source, the CT DEP did not require UI to obtain a modified source permit for BHS 3. The state did, however require UI to obtain an operating permit to convert to coal.

Rationale

NSPS (Subpart D): 40 CFR 60.14(e)(4) exempts a change to a facility (in this case, a boiler) from consideration as a modification if the emissions increase from such change results from use of an alternative fuel, provided the use of the alternative fuel could be accommodate under the facility's construction specifications as amended prior to the change. UI's designs for BHS 3, as well as their

contract, specified all equipment necessary for burning coal as the primary fuel.

All major equipment was installed. It is Region I's opinion that the alterations to the boiler necessary to burn coal presently result from the 1968 alterations to the boiler that were made to enable the boiler to burn oil, and as such do not constitute a modification.

NSPS (Subpart Da): 40 CFR 60.40a(d) exempts an oil burning unit from the provisions of Subpart Da if such unit is modified to burn coal.

PSD: 40 CFR 52.21(b)(2)(iii)(e)(1) exempts a change to a source (in this case, the generating station) from consideration as a major modification if such change results from the use of an alternative fuel, provided the source could accommodate the alternative fuel prior to January 6, 1975. BHS 3 was built before this date and was designed to burn coal, and is therefore exempt from PSD. If your office concurs with Region I's determination, please advise us by June 24, 1983. If your office does not concur, please forward your determination by July 8, 1983.

Since several parties are anxiously awaiting this determination we would appreciate your response by the dates indicated above.

If you should have any questions, or should need additional information, please contact John Courcier (FTS 223-5137) of my staff.

cc: Rich Biondi, DSSE
Marcus McCraven, UI
Leonard Bruckman, CT DEP
Mike Trutna, QAQPS

EXHIBIT E

CAPITAL COST ESTIMATE

(1982 Dollars)

	Total Project Cost (in thousands)
Coal Handling	$ 921
Coal Pile	418
Dust Suppression	1,256
Fire Protection	1,159
Boiler	4,443
Bottom Ash System	4,256
Econ. Ash Removal	422
Precipitator	4,487
Precipitator Ash System	2,590
Electrical	3,342
Controls	472
Computer	484
OSHA & Safety	1,100
Blr., Econ. & A.H. Wash	85
Waste Water	242
Sort Facilities	2,474
Site Improvements	341
Ash Management	623
O&M Training	1,940
Owner's Cost	1,725
Legal	120
Permits	152
Consultants	406
Spare Parts Inventory	1,293
TOTAL	$34,751

Attachment 2
6/29/83

ENVIRONMENTAL CONTROLS:		
Coal Pile	$ 418,000	
Dust Suppression	1,256,000	
Bottom Ash	4,256,000	
Econ. Ash Removal	422,000	
Precipitator	4,487,000	
Precipitator Ash System	2,590,000	
Controls	472,000	
Waste Water	242,000	
Ash Management	623,000	
		$14,766,000
MISCELLANEOUS SUPPORT ITEMS:		
Support Facilities (Building to house Personnel & Computer)	$2,474,000	
Site Improvement	341,000	
O & M Training	1,340,000	
Owner's Cost (UI Engr.)	1,725,000	
Legal	120,000	
Permits	152,000	
Consultant	406,000	
Spare Parts	1,293,000	
Fire Protection	1,159,000	
OSHA	1,100,000	
Coal Handling	921,000	
Electrical	3,342,000	
Computer	484,000	
		$15,457,000
Boiler	$4,443,000	
Blr., Econ. Air Heater Wash	85,000	
		$ 4,528,000
TOTAL ESTIMATED COST AT TIME OF FILING		$34,751,000

EXHIBIT 138

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA, Plaintiff,	:	
ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP Plaintiff-Intervenors	:	Civil Action No. 1:00 CV 1262
v.	:	
DUKE ENERGY CORPORATION, Defendant.	:	

Washington, D.C.

Monday, November 25, 2002

Videotaped deposition of RANAJIT SAHU, a witness herein, called for examination by counsel for Defendant Duke Energy Corporation in the above-entitled matter, pursuant to notice, the witness being duly sworn by MARY GRACE CASTLEBERRY, a Notary Public in and for the District of Columbia, taken at the offices of U.S. Department of Justice, 1425 New York Avenue, N.W., Washington, D.C. at 9:22 a.m., Monday, November 25, 2002, and

the proceedings being taken down by Stenotype by MARY GRACE CASTLEBERRY, RPR, and

* * *

[463] Q. Mr. Sahli, if I told you that there is a project at a 70 megawatt unit that involved the replacement of the lower economizer bank, a large portion of the drum circuit, all of the feed water heaters and all of the condensate and heater drain pumps and this project was done in, let's say the mid-'80s.

A. Okay.

Q. Do you have an opinion about whether a PSD permit would be required for such a project?

A. No, not just by what I heard.

Q. What do you need to hear more?

A. Well, I mean people have to determine if it is excludable or not, some of these physical changes. Looks like physical changes were made. That's about all I can ascertain from your –

Q. And I described the physical changes to you. Let's take them step by step. In your opinion, are these physical changes that I described to you or actually these replacements that I described to you, [464] in your opinion, are they excludable?

A. Again, I'm not here to opine about routine repairs so –

Q. I understand. I still would like to have your opinion.

A. Would you run those by me again?

Q. Sure. Replacement of the lower economizer bank, a large portion of the drum circuit, all of the feed water heaters and all of the condensate and heater drain pumps.

A. They seem like major changes.

Q. So in your opinion, that would be not excluded?

A. Right.

Q. So those would be a physical change?

A. That would be a physical change, in my opinion.

Q. And to determine whether there was an emission increase for such a project, what test would you apply in 1985?

A. An actual to potential test.

Q. And what test would you apply in 1989?

A. 1989, you said? I would apply an actual to potential test.

Q. What test would you apply in 1991?

[465] A. I believe I would still apply an actual to potential test.

Q. And if you knew that no emissions control were put on that unit and you're not aware of any permit limitations that required a curtailment of hours of operation, is it reasonable to assume, based on the information that you have, that this project would have triggered PSD?

A. Is this a coal fired unit?

Q. It's a coal fired unit.

A. Is it burning low sulfur coal, high sulfur coal?

Q. Let's start with low sulfur coal.

A. Does it have an ESP? I don't know what the unit has or doesn't have.

Q. It's a 70 megawatt unit in the mid-1980s It's likely to have an ESP, its not likely to have any NOx controls.

A. Correct.

Q. And it's not likely to have any SO2 controls. It's pre-NSPS unit.

A. Okay.

* * *

EXHIBIT 143

ENVIRONMENTAL PROTECTION AGENCY

FEB 13 1978

MEMORANDUM

SUBJECT: MAYTEP, Determination of Applicability

FROM: Director
Division of Stationary Source Enforcement

TO: Thomas W. Devine, Chief
Air Branch – Region I

This office has reviewed your determination of applicability of the PSD regulations to MAYTEP. Our comments are as follows:

1. The discussion in item 1 leads me to the conclusion that MAYTEP would not be subject to the revised NSPS for steam generators. This definition is only a part of draft regulations and in no way should be relied upon for any action taken by the Agency. Further, exclusion from NSPS does not indicate that the source should not be subject to PSD. NSPS are technology based standards developed for very specific source categories. PSD source categories, on the other hand, must be considered as broadly as possible since our objective is to protect air quality to the maximum degree. Rather than relying on a draft regulation, we should consider the PSD proposal (11/3/77) which includes an expanded list of source categories and a 250 tons/year potential emission catch-all. It seems reasonable to me that any determination made should move closer to the intent of Congress, instead of moving further from it.

2. We believe entirely too much reliance is made upon the NSPS. The mere fact that a source is or is not

covered by NSPS should not be the overriding factor when determining applicability to the PSD requirements. Since this source will emit approximately the same amount of pollution as one that was designed to produce 100% electricity, it makes no sense to me to exclude it from a review which is concerned with those emissions and their effect on ambient air quality.

3. Your decision that the source category "steam electric plants of more than 1000 x 10^6 BTU/hr heat input" was chosen to cover only large steam electric power plants and not steam generating units is false and is not founded by any previous Agency actions. The Agency has always held that the source categories should be interpreted as comprehensively as possible in order to preserve the spirit and intent of the regulations.

4. Your discussion in item #4 is not very convincing when the main consideration should be air pollution and its effect on air quality. Neither the owner of the source of the emissions nor the source's use should play any role when considering its applicability.

5. What occurs as a result of an action taken by another program (effluent guidelines) should not be a controlling factor within the air program particularly if the definition is contrary to the one already in use.

6. Your discussion in item #6 may be correct, but since we are implementing a regulation that exists now, we cannot predict what my occur sometime in the future, nor can we base our decision on some future regulatory exemption which can only be triggered by what amounts to a political decision.

7. That there will be no environmental benefit realized by including this source in the PSD regulations, should not affect EPA's decision of whether or not to cover this source. The precedent this establishes could prove to be very damaging when attempting to implement the PSD requirements with similar sources. In addition similar sources which may have already complied with these requirements may now object to their applicability based on this decision.

In summary, it is the opinion of this office that MAYTEP qualifies as a 1000 million BTU/hr heat input fossil fuel steam electric plant and that it is subject to the PSD requirements. Further, it is the function of DSSE to provide guidance for interpretations which address the implementation of these regulations. Reliance upon opinions obtained from other EPA offices without consulting DSSE will not ensure uniform national policy for implementation of these regulations. Agency policy requires that DSSE, after consulting with other EPA offices, make the final recommendation for interpretation of these requirements.

If you have any comments or questions, please contact Rich Biondi (755-2564) of my staff.

Edward E. Reich

cc: Mike Trutna – CPDD
Dick Rhoads – CPDD

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

DATE: JANUARY 6, 1978

SUBJECT: MATEP, Determination of PSD Applicability

FROM: Thomas W. Devine, Chief

The Files

The following evaluation is based on the information available to Region I as of this date (December 20, 1977). This information was supplied by the Commonwealth of Massachusetts and United Engineers and Contractors (principle consultant for MATEP). It is the Agency's determination that this facility is not subject to the present significant deterioration regulations which remain in effect until March 1. If the facility receives all required permits from the state prior to March 1, 1978 and since it has already begun the construction under an earlier state permit it will not be subject to significant deterioration requirements in effect after March 1, 1978. If the necessary permits are not issued, the source would be subject to PSD regulations as proposed in the *Federal Register* at this time.

Following is the basis for this determination:

1. The proposed Standards of Performance for New Stationary Sources which is expected to be in the Federal Register prior to February 1, 1978 constitutes a partial revision to 40 CFR Part 60, Subpart D. Electric utility power plants are now defined as any facility where more than one-third of the steam generated is ultimately used to produce electric power for sale. MATEP would not be included in this category as only 20 to 25% of the steam

generated is used to ultimately produce electric power and the distribution of that power would not be included in the definition of "for sale".

2. Sources which would not be included under the above definition would remain covered under 40 CFR Part 60, Subpart D and in the proposed revision are identified as industrial facilities that produce electric power or steam for their own use or that sell less than one third of their electrical steam generating capacity. This facility cannot be construed as being an industrial facility. The remaining section under 40 CFR Part 60.40 is applicable to any fossil fuel fired steam generating unit assuming that that definition would not be further redefined by the proposal. This facility is subject to New Source Performance Standards under this definition and has been reviewed on that basis by the state and conforms with standard requirements. (It also would meet all presently applicable PSD requirements.)

3. The only type of stationary source included within the present significant deterioration regulations which this source might fall under would be fossil fuel *steam electric* plants of more than 1000 x 10^5 BTU/hour heat input. This specifically identified source category is different from the NSPS source category referred to above. This category was chosen to cover large steam electric power plants not steam generating units. The Agency's choice of the 19 major source categories to be covered by the presently applicable PSD requirements has been upheld in court with the recognition that they were deliberately limiting.

4. MATEP is incorporated under Chapter 121A of the Massachusetts General Laws and as such is a non-profit

corporation. MASCO, also a non-profit corporation, will operate the facility and distribute power to its members. MATEP will be reimbursed by those members based on use to defray operating and amortization costs. The only distribution outside of the MASCO membership will be to the Mission Hill Housing project which is owned by Harvard University (a member of MASCO). The project will not receive any power, only steam and chilled water. As a non-profit organization which is not selling anything this facility would not be included within the definition of utility or industrial under the proposed NSPS revision for el ctric utility steam generating units.

5. This determination is also consistent with the definition under "Effluent Guidelines", the standards for the NPDES program (40 CFR 423.1, Steam Electric Power Generating Point Source Category) which define applicability as being limited "to discharges resulting from the operation of a generating unit by an establishment primarily engaged in the generation of electricity for distribution and sale". This constitutes an Agency interpretation of "steam electric", and this definition would not include a source like the MATEP facility, since it is not primarily engaged in the generation of electricity.

6. It should also be recognized that this source could be exempted from PSD coverage by the Governor of the Commonwealth of Massachusetts in approximately 9 months after the state has revised its SIP to include significant deterioration within their new source review program.

7. It is the Agency's opinion, after reviewing the source design, that a further significant deterioration permit would not result in any further environmental

improvement over and above that which is going to be required by the state's permits.

In summary, we feel that the PSD categories were intended to cover certain specific types of source which were major polluters. No catch-all category was included e.g., total emission or total heat input, although this would not have been difficult. The MATEPZfacility is closest to the "Fossil-Fuel Steam Electric Plant" category but does not fit because it primarily generates steam, not electricity, and its electric-generation related beat input is well below the 1,000 million BTU per hour level (equivalent to 235 million BTU per hour). To attempt to include the facility in this category would represent a substantial departure from the Agency's intent.

cc: R. Biondi, DSSE

EXHIBIT 148

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA,

Plaintiff(s),

ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP,

vs. Case No. 1:00CV126

DUKE ENERGY CORPORATION,

Defendant(s).

VIDEOTAPED
DEPOSITION

WITNESS:	JOHN HEWSON
DATE:	Monday, December 17th, 2001
TIME:	9:30 a.m.
LOCATION:	Allgood, Childs & Mehrhof 615 Telfair Street Augusta, Georgia
TAKEN BY:	Attorneys for the Defendant
REPORTED BY:	LISA D. JETER, Registered Professional Reporter

* * *

[64] '99. Approximately one year after the inspection was done.

It was shortly thereafter that Mr. Baig left the agency. All the information had come in. And then at that time, I was officially told that my top priority and my job was, again, to do things for the electric utility industry full-time. And I, at that point, reviewed all of the information that had come in on the information request.

Q. For Tampa Electric?

A. For Tampa Electric. It was approximately 25 boxes of information – 22 boxes, I think it was. And I sat in a room about like this for a few months and reviewed the information. And that is what I did from April of '99 through – through the rest of that year.

But the next major event – well, there were a lot of things going on, and I'm not going to be able to remember exactly when. But there were a lot of meetings in headquarters. I was probably going to a minimum of four meetings a year in headquarters.

Q. All about the utility –

A. That's correct.

Q. – enforcement initiative?

A. That's correct. I believe – yeah, okay. It would have been in '99 that we had, I believe it was [65] three meetings regarding how to do the emission calculations.

Q. And those meetings were occurring in 1999?

A. There were – again, I better not – it may have been two. It was either two or three meetings in '99, and these would be generally two- or three-day meetings, generally at the Department of Justice. It would be probably, you know, a minimum of four justice attorneys.

Oh, at this point, Jim Jackson was no longer associated with the electric utility initiative directly. He had been replaced by Greg Jaffe.

Q. Why did that replacement occur?

A. It's my understanding that Jim Jackson was working on another EPA initiative to look into the compliance status at oil refineries. And so he couldn't – you know, again, this would have been his management's call. I – so really it's my speculation. But, you know, his management, Bruce Buckheit, had put him on the – to spearhead an initiative for the petroleum refineries, and then he replaced him with Greg Jaffe.

Q. So you had at least two meetings in 1999 about how to do emission calculations –

A. That's correct.

* * *

[69] Q. How did – how did you learn how to do the emission calculations?

A. Through the conversations that we had had about it, and the conversations that I had had with Gregg Worley – and I – at this point, I believe, Jim Little was on board with EPA – conversations I would have had with Jim Little, and my reading and interpreting of the regulation.

Q. And these conversations you're talking about, where you learned how to do the emission calculations to you could make this presentation in the fall of '99, are these – are we talking about conversations that occurred in 1999 at the other two meetings?

A. I think that in the fall of '99, one of the – that in the fall of '99, the different people were putting different emphasis on different emission calculations. And I think that this was really a meeting to make sure that EPA spoke with one voice and came up with its best – its policy on what – what the procedure should be when you do an emission calculation. I guess the thing with the emission calculations is that there are several different calculations that can and probably should be done.

And so – and each situation is different with the – with respect to a major modification. So this [70] was really a training to see what the other regions were doing to date and how they were doing the emission calculations, and to inform the Department of the Justice attorneys and others who were learning about PSD for the first time and were not as familiar with the process.

Q. How did it happen that the regions were doing the emission calculations in different ways –

MR. DION: Objection to form.

THE WITNESS: I would –

BY MR. COTTINGHAM:

Q. – in 1999?

A. I would say that, again, there is – if you look at the PSD rule itself, as it stands now, it's – there is something called "actual emissions," is one of the definitions, one of the terms that's defined. I can't remember exactly, but I believe that the term has approximately five subletters under it, in how it's defined. In other words, it can be defined as what most people would consider actual emissions, kind of the way Webster would – would – what's

actually put into the environment, loaded into the environment, is the first definition that's given.

* * *

EXHIBIT 189

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
[LOGO] Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

May 25, 1990

MEMORANDUM

SUBJECT: Letter to John Boston,
Wisconsin Electric Power Company (WEPCO)

FROM: Gerald A. Emison, Director /s/ Gerald A. Emison
Office of Air Quality Planning and Standards
(MD-10)

TO: William G. Rosenberg, Assistant Administrator
for Air and Radiation (ANR-443)

The attached letter to John Boston of WEPCO provides the company with the Environmental Protection Agency's (EPA's) response to the court decision in the *WEPCO* case. As you will recall, although the WEPCO issue has come to be associated with the applicability of the Agency's new source review program to utility companies also subject to acid rain requirements, the original case involved the replacement of a major component at the Port Washington power plant owned by WEPCO. The WEPCO sued on EPA's determination that the replacement, and other associated changes, made the plant subject to EPA's new source review requirements. The court upheld EPA's determination in large part, but concluded that the Agency's method of determining whether the WEPCO action was subject to the prevention of significant deterioration (PSD) rules needed to be revised. The court found that in calculating whether the

particular kind of change would increase emissions, EPA should make a projection of the plant's actual emissions in the future, rather than assuming that the plant would operate at its maximum capacity.

The letter to Mr. Boston sets forth the way in which EPA has calculated the WEPCO plant's "estimated future actual emissions." In making this calculation we have relied on the utility's own data concerning the plant's historical operations and the company's projections of the plant's future operation and emissions rates, as reflected in papers filed with the Wisconsin Public Utility Commission and the Wisconsin Department of Natural Resources.

The result is that WEPCO is subject to PSD but only for nitrogen oxides (NO_x). The permit will require the same enforceable limits on the fuel sulfur content and particulate controls as those proposed by WEPCO. It will not restrict future operating levels.

With regard to the new source performance standards (NSPS), WEPCO proposes to avoid triggering NSPS for the reconstruction by further controlling two units to a level sufficient to offset projected emissions increases. Unit 5 is not being renovated at this time. If in the future it is renovated, it would be subject to NSPS. We have discussed this with the company and find their proposal acceptable.

On April 6, my staff met with WEPCO representatives to discuss our revised applicability determination. On April 10, WEPCO informed us that they would not challenge such an applicability determination and would proceed with the necessary PSD permit for NO_x if the State found that no further NO_x control is necessary. A PSD permit application for NO_x has already been submitted by WEPCO to the State. The State has agreed that the

Port Washington boilers' characteristically low emissions of NO_x represent best available control technology for the renovation project. The WEPCO is anxious to receive the attached letter from EPA so that it can proceed with the processing and issuance of the State permit.

Both WEPCO and Wisconsin are aware of, and concur with, the basis for our revised determination and have indicated no disagreement. This letter will allow WEPCO and the State to process the PSD permit.

Attachment

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA Plaintiff, v. DUKE ENERGY CORPORATION, Defendant.	)	CIVIL NO. 1:00CV1262

EXHIBITS IN SUPPORT OF UNITED STATES RESPONSE TO DUKE'S PROPOSED SUPPLEMENTAL MEMORANDUM IN SUPPORT OF ITS MOTION FOR RECONSIDERATION

(Filed Oct. 8, 2003)

* * *

EXHIBIT 1

ANALYSIS OF THE POTENTIAL COST, ENVIRONMENTAL AND ENERGY IMPLICATIONS OF EPA'S RECENT WEPCO AND GREENWOOD DECISIONS

Prepared For
The Utility Air Regulatory Group

By
ICF Resources Incorporated

January 1990

* * *

These oil capable plants that might switch to gas in the future were, therefore, identified as potentially affected.

Two types of data were used to identify those plants that were "only oil capable": historic fuel consumption data and the Energy Information Administration's (EIA) *Inventory of Power-plants.*

- The Utility Data Institute (UDI) provided historic fuel consumption data for the period 1980-1987. Using the UDI data, "only oil capable" plants were identified as those that did not use *any* gas over the entire period.[1]

[1] It is possible that a small amount of gas might be used at a plant for flame stabilization or other purposes without indicating that the plant was gas capable. For this analysis, however, it was conservatively assumed that consuming even a small quantity of gas indicated that the plant could be considered gas capable.

- Oil powerplants in EIA's *Inventory of Powerplants* which were not listed as having the capability of burning gas (as either the primary or secondary fuel) were also defined as oil capable.

An initial list of potentially affected plants was developed combining these two sources, and then certain plants were eliminated because it was assumed that they would not be affected by the modification rule. Those plants that were not forecast to switch to gas over the forecast period were eliminated because they were assumed to not engage in activities that could trigger the rule. It was assumed that most "oil capable" plants, except some plants in New England and New York where gas access might be limited, would switch to gas. Those plants in the Northeast that would not be expected to switch to gas were identified based on previous electric utility and gas market studies conducted by ICF Resources, as well as based on a survey of electric utilities. Based on this research, 26 units (with a combined capacity of almost 6 GW) were eliminated from the list.

It was assumed that the "oil capable" plants identified as potentially affected under the modification rule would switch to gas in the near-term, given the relative prices of gas and oil assumed in the base case. Thus, these plants (totaling 22GW) were all assumed to be affected by the rule in 1995.

Affected Coal Plants

In the Wisconsin Electric Power Co. (WEPCo) case, the Port Washington coal-fired powerplant was targeted by EPA under the modification rule because it had been

operating at a low capacity factor and reduced capacity for a number of years prior to its planned refurbishment. Based on the plant's recent performance, EPA determined that an emission increase would result from the maintenance activities, which were expected to return the plant to its original operating levels. Therefore, it was assumed that coal plants with consistently poor performance or availability could be targeted by EPA when they refurbished.[2]

It is impossible to project future performance levels and availability, so historic capacity factor data was used to identify poorly performing plants. Using capacity factor data provided by UDI and an ICF Resources database (which was developed using FERC Form 767 data), powerplant units with low capacity factors over the period 1986-1988 were identified. It was assumed that these plants would become "affected plants" at age 30 when they refurbished, because refurbishment would be expected to improve performance which could result in an emissions increase.

A three-year average capacity factor was computed for the period 1986-1988. Excluding units already meeting NSPS, units with average capacity factors of less than 30 percent over the period were identified as potentially affected by the modification rule. Those few units that were already scrubbed were eliminated from this list reflecting the likelihood that the existing scrubber designs

* * *

[2] Although the actual age at which a plant might undertake refurbishment activities might vary, it was assumed that most plants would begin these activities at around age 30. Thus, for simplicity it was assumed that all affected plants would be targeted at age 30.

could meet NSPS requirements. Those units with net dependable capacity of less than 50 MW were eliminated from this list as well because these units were assumed not to refurbish in the base case and retire in 45 years. In addition, units forecast to repower in the base case were also eliminated from the list because these plants were already assumed to have to comply with NSPS regulations in the base case. A total of 15 GW of coal capacity was assumed to be affected by 2010 based on these criteria.

High Impact Cases

In the High Impact cases, much broader definitions were used to identify affected powerplants because it was assumed for these cases that EPA would interpret the rule more aggressively. In fact, in these cases, it was assumed that almost every powerplant would undertake some type of maintenance or refurbishment activity over its lifetime that would trigger the modification rule. Thus, in the High cases it was assumed that EPA would target almost all coal, oil and gas powerplants at 30 years of age. As in the Low cases, moreover, those oil only plants forecast to switch to gas in the base case forecast were also considered affected in 1995.

Certain groups of plants were considered unlikely to be affected by the modification rule, however. On both the oil/gas and coal lists, for example, powerplants with net dependable capacity of less than 50 megawatts were not considered affected consistent with the assumption used in the base case that these units would not likely engage in major maintenance/refurbishment and would retire after 45 years (instead of 65 years for plants engaging in major maintenance/refurbishment). For coal plants, moreover,

those units that were forecast to repower, had already reconverted from oil to coal, or were already scrubbed were also not considered to be affected.

Given the cost differential between conventional NO_x controls and SCR, it was assumed that plants required to install SCR under the modification rule would choose early retirement, while plants that could net out of PSD by installing conventional controls would choose to refurbish or fuel switch. Thus, all non-NSPS oil/gas plants were assumed to refurbish with conventional NO_x controls and the few NSPS oil/gas plants were assumed to retire early.

Affected Coal Plants

It was assumed that coal plants could be required under the modification rule to comply with PSD and/or NSPS. NSPS regulations apply if an emissions increase measured in kilograms per hour occurs, which is typically associated with an increase in capacity. PSD regulations, in contrast, apply if an emissions increase measured in tons per year occurs, which is typically associated with an increase in capacity factor.

For some pollutants, NSPS and PSD regulations require installation of similar pollution control equipment. For other pollutants, such as NO_x, however, different pollution control equipment is required. NSPS NO_x regulations, for example, require installation of conventional NO_x controls, while PSD regulations require installation of SCR, which is more stringent and, hence, more expensive. As with oil/gas plants, however, coal plants could "act out" of PSD by making smaller reductions by reducing the plant's overall emissions or emissions at other plants to

the point where emissions before and after refurbishment are the same.

For this analysis, it was assumed that affected coal plants would be required to comply with NSPS regulations for two reasons: (1) many coal plants could experience small gains in capacity associated with refurbishing, either by returning a plant to its original design capacity or by rerating the plant which would require NSPS to be met; and (2) those plants that experienced *only* an increase in capacity factor and hence should be targeted by PSD regulations could potentially install less stringent controls and "net out." It is unclear what baseline would be allowed in netting out of these reductions and NSPS was assumed as a mid-range assumption (less stringent than PSD but more stringent than allowing fuel switching for netting out). Thus, it was assumed that coal plants would be required to comply with NSPS for SO_2, NO_x and particulates (TSP).

Compliance with either NSPS or PSD SO_2 regulations would require installation of a retrofit scrubber. NO_x regulations could be met by installing conventional NO_x controls at most plants except those with wet-bottom or cyclone boilers, which cannot use conventional NO_x controls and would thus have to install SCR. It was assumed that NSPS particulate standards could be met by either increasing plate area in an affected plant's electrostatic precipitator or by flue gas conditioning.

To determine which compliance strategies would be chosen by different types of coal plants, a detailed economic analysis was prepared which compared the present value of costs over a 30-year period of refurbishing and installing the required pollution control equipment to the

ost of retiring in 15 years and building new capacity. The esults of these analyses are summarized in Table 3 and escribed below. Unlike oil/gas plants, it was assumed nat the compliance choices of coal plants would change if cid rain legislation is enacted because of the added value f SO_2 reductions under a bill. Thus, the assumed compli- nce choices for both the "No Acid Rain" and the "With cid Rain" cases are presented below.

* * *

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA,	)	
Plaintiff and Counter-Defendant,	)	
and	)	
ENVIRONMENTAL DEFENSE; NORTH CAROLINA SIERRA CLUB; and NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP CITIZEN LOBBY/ EDUCATION FUND,	)	
Intervenor-Plaintiffs,	)	
v.	)	CIVIL NO. 1:00CV01262
DUKE ENERGY CORPORATION,	)	
Defendant and Counter-Claimant.	)	

ORDER

(Filed Feb. 23, 2004)

BULLOCK, District Judge

On December 23, 2003, Plaintiff moved for reconsideration of the court's August 26, 2003, summary judgment order, or, in the alternative, to certify the order for interlocutory appeal. Plaintiff contends that the order should be reconsidered in light of documents recently made available to the Plaintiff that the Defendant received from

counsel for the Utility Air Regulatory Group, a non-profit association of electric utility companies and trade associations of which Defendant is a member. Plaintiff contends that these documents show that Defendant knew, or should have known, that EPA's test for "routine maintenance" focused on routine maintenance at an individual unit in the relevant industry. Plaintiff also contends that Duke also knew that the agency contended PSD was triggered by increases in total annual emissions notwithstanding the absence of an increase in maximum hourly emission rates.

Defendant contends that reconsideration is not warranted because Plaintiff's "newly discovered evidence" is not relevant to the issues decided by the court, is cumulative to evidence that the court has already seen, and is not inconsistent with the court's order. Defendant also opposes certification for interlocutory appeal.

In drafting its opinion and order, the court undertook a painstaking review of the statutory and regulatory framework. Relying on the statutes and legislative intent, the court held that "[i]n order to give PSD RMRR exemption its proper scope, this provision must be defined according to what is routine maintenance, repair, and replacement within the relevant source category. This construction is compelled by the statutory mandate of the PSD program and congressional intent." *United States v. Duke Energy Corp.*, 278 F. Supp.2d 619, 631 (M.D.N.C. 2003). The court also found "based on the PSD rules, the contemporaneous interpretations of the PSD rules, and the statutory language incorporating the NSPS concept of modification into PSD, post-project emissions must be calculated on an annual basis, measuring emissions in tons per year, and in calculating post-project emissions

levels, the hours and conditions of operation must be held constant." *Id.* at 640. Thus, even assuming that the EPA may have spoken out of both sides of its mouth on these issues, the primary basis for the court's holding was the plain statutory language and congressional intent. The question of fair notice, the basis for the Plaintiff's relevance argument, is no longer an issue for trial.

In the alternative, Plaintiff asks the court to certify its order for an immediate appeal pursuant to 28 U.S.C. § 1292(b). The statute requires that certification be based upon the district judge's "opinion that such order involves a controlling question of law as to which there is substantial ground for a difference of opinion and that an immediate appeal from the order may materially advance the ultimate termination of the litigation." All three requirements must be satisfied. Although not in the statutory language, courts have held that to warrant an interlocutory appeal the appellant must demonstrate "'that exceptional circumstances justify a departure from the basic policy of postponing appellate review until after the entry of a final judgment.'" *Coopers & Lybrand v. Livesay,* 437 U.S. 463, 475 (1978) (quoting *Fisons, Ltd. v. United States,* 458 F.2d 1241, 1248 (7th Cir. 1972)). Because certification should not be granted routinely, procedural requirements for interlocutory appeal should be strictly construed. *See Myles v. Laffitte,* 881 F. 2d 125, 127 (4th Cir. 1989).

This case began in December 2000. Extensive discovery has been completed, dispositive motions have been ruled upon, and the case is essentially ready for trial. An interlocutory appeal would delay rather than advance the ultimate termination of this case. Further, it does not appear that a trial would be unusually lengthy. Plaintiff has conceded that the court's ruling that PSD is triggered

only by projects that increase the unit's maximum hourly emissions rate will likely be determinative "of most if not all of the PSD claims in this case." Plaintiff has also admitted that it does not contend that projects of the type performed by Duke are unprecedented or even uncommon in the utility industry. While these standards are ones on which reasonable minds might disagree, this alone does not warrant interlocutory appeal. All three requirements of the statute must be viewed together. Regardless of whether Plaintiff has raised a controlling question of law as to which there is substantial ground for differences of opinion, the court does not believe the possibility that the court of appeals would entertain an interlocutory appeal of the court's summary judgment order would materially advance the termination of this litigation.

NOW, THEREFORE, the Plaintiff's motions for reconsideration of the court's summary judgment order, and, alternatively, to certify its order for interlocutory appeal [Doc. #268], are **DENIED**.

The court will direct the Clerk to schedule this case for trial during the July term and provide proper notice to the parties.

/s/ _____
United States District Judge

February 23, 2004

THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA, Plaintiff, and ENVIRONMENTAL DEFENSE, ET AL., Plaintiff-Intervenors, v. DUKE ENERGY CORPORATION, Defendant.	)	Civil Action NO. 1:00 CV 1262

STIPULATIONS IN SUPPORT OF JOINT MOTION FOR ENTRY OF FINAL JUDGMENT, TO STAY CONSIDERATION OF RULE 72(a) OBJECTIONS, AND TO STAY ENFORCEMENT OF DISCOVERY ORDER

(Filed Apr 13, 2004)

Pursuant to the Joint Motion for Entry of Final Judgment To Stay Consideration of Rule 72(a) Objections, and To Stay Enforcement of Discovery Orders; Plaintiff United States of America, Plaintiff-Intervenors Environmental Defense, *et al,* Defendant Duke Energy Corporation ("Duke Energy"), and non-party Utility Air Regulatory Group ("UARG") submit the following stipulations:

1. Plaintiff and Plaintiff-Intervenors stipulate that their contention that each of the projects at issue in this case resulted in a significant net emissions increase within

the meaning of the relevant PSD regulations is based solely on their contention that the projects would have been projected to result in an increased utilization of the units at issue.

2. Plaintiff and Plaintiff-Intervenors stipulate that they do not contend that the projects at issue in this case caused an increase in the maximum hourly rate of emissions at any of Duke Energy's units.

3. Plaintiff and Plaintiff-Intervenors stipulate to the dismissal, with prejudice, of those Claims for Relief which are not PSD claims (the "Non-PSD Claims"), *i.e.*, the even-numbered Claims for Relief in the Complaint, as incorporated by reference in the Complaint-in-Intervention.

4. Defendant stipulates to the dismissal of its counterclaims in this action, without prejudice to revive such counterclaims in the event of a remand of this case as the result of an appeal. In the event of a remand, Plaintiff and Plaintiff-Intervenors will not oppose Defendant's counterclaims on timeliness or statute of limitations grounds.

5. The Parties stipulate that the Court stay enforcement of Magistrate Judge Eliason's Orders regarding the UARG documents (Docket Nos. 164, 244 and 250) and stay consideration of Duke Energy's Rule 72(a) Objections (Docket No. 252) and UARG's Rule 72(a) Objections (Docket No. 251 and 281) to those orders. Upon entry of such a stay and a final judgment and order pursuant to the Joint Motion for Entry of Final Judgment, Plaintiff shall return the documents that are the subject of those Orders and Objections and any and all copies of these documents to Defendant. Defendant shall retain and preserve these documents.

6. Upon entry of an Order staying enforcement of Magistrate Judge Eliason's Orders regarding the UARG documents (Docket Nos. 164, 244 and 250) and staying consideration of Duke Energy's Rule 72(a) Objections (Docket No. 252) and UARG's Rule 72(a) Objections (Docket No. 251 and 281), Plaintiff and Plaintiff-Intervenors agree to the withdrawal of the documents submitted as Exhibits 166-176 in support of Plaintiff's Motion for Reconsideration (Docket No. 268) and stipulate that these documents and the other documents that are the subject of Duke Energy's Rule 72(a) Objections (Docket No. 252) and UARG's Rule 72(a) Objections (Docket No. 251 and 281) shall not be part of the record in any appeal of the final judgment entered pursuant to the Joint Motion for Entry of Final Judgment. Plaintiff and Plaintiff-Intervenors further stipulate that they shall not refer to these documents and the other documents that are the subject of Duke Energy's Rule 72(a) Objections (Docket No. 252) and UARG's Rule 72(a) Objections (Docket No. 251 and 281) in any of their argument or filings in the course of that appeal.

7. In the event of a remand after appeal of a final judgment entered pursuant to the Joint Motion for Entry of Final Judgment, Plaintiff and Plaintiff-Intervenors reserve the right to seek to lift the stay of enforcement of Magistrate Judge Eliason's Orders regarding the UARG documents (Docket Nos. 164, 244, and 250), and Defendant and UARG reserve the right to seek to lift the stay of consideration of Duke Energy's Rule 72(a) Objections (Docket No. 252) and UARG's Rule 72(a) Objections (Docket No. 251 and 281).

8. With respect to the miscellaneous action pending in the United States District Court for the District of

Columbia relating to subpoenas served upon UARG, Plaintiff agrees to withdraw the subpoenas served on UARG in *United States v. Duke Energy Corp.* (M.D.N.C.). If this case is remanded as the result of an appeal, UARG and Defendant will not oppose the enforcement of new subpoenas as untimely.

9. Defendant stipulates to the withdrawal of Duke Energy's Motion for Sanctions (Docket No. 286) with prejudice, and Duke Energy's Motion to Strike Exhibits 166-176 (Docket No. 282), without prejudice.

10. Plaintiff and Plaintiff-Intervenors reserve the right to appeal the final judgment as to the PSD claims in this action. *i.e.*, the odd-numbered Claims for Relief in the Complaint, as incorporated by reference into the Complaint-in-Intervention. Defendant agrees and stipulates that the final judgment entered in connection with these stipulations is appealable by Plaintiff and Plaintiff-Intervenors as of right pursuant to 28 U.S.C. § 1291 with respect to the PSD claims in this action.

Dated: April 13, 2004

Respectfully submitted,

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No. 05-848

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In The

Supreme Court of the United States

ENVIRONMENTAL DEFENSE, et al.,

Petitioners,

v.

DUKE ENERGY CORPORATION, et al.,

Respondents.

On Writ Of Certiorari To The United States Court Of Appeals For The Fourth Circuit

BRIEF FOR THE PETITIONERS

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JULY 2006

QUESTIONS PRESENTED

In this civil enforcement action under the Clean Air Act, the Fourth Circuit ruled that EPA's definition, embodied in a 1980 regulation, of emissions "increases" for purposes of the Prevention of Significant Deterioration (PSD) program violates the Act because it differs from a regulatory definition EPA employs to measure emissions increases under another program under the Act, the New Source Performance Standards (NSPS). Both the court's holding and its analysis of the statute conflict with decisions of other courts, including a decision rendered by the D.C. Circuit rejecting challenges to the very regulations at issue in this case, *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2005). The questions presented are:

1. Whether the Fourth Circuit's decision violated Section 307(b) of the Act, which provides that national Clean Air Act regulations are subject to challenge "only" in the D.C. Circuit by petition for review filed within 60 days of their promulgation, and "shall not be subject to judicial review" in enforcement proceedings, 42 U.S.C. 7607(b); and

2. Whether the Act's definition of "modification," which turns on whether there is an "increase" in emissions and which applies to both the NSPS and PSD programs, rendered unlawful EPA's longstanding regulatory test defining PSD "increases" by reference to actual, annual emissions.

PARTIES TO THE PROCEEDINGS

Petitioners Environmental Defense, North Carolina Sierra Club, and North Carolina Public Interest Research Group Citizen Lobby/Education Fund intervened as plaintiffs in the district court and were appellants in the court of appeals. Respondent the United States was plaintiff in the district court and an appellant in the court of appeals. Respondent Duke Energy Corporation was defendant in the district court and was the appellee in the court of appeals.

STATEMENT PURSUANT TO RULE 29.6

None of the petitioners that are corporations has a parent company, and no publicly held company owns 10% percent or more of the stock of any such corporate petitioner.

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